U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-293 014

Industrial Boilers Fuel Switching Methods, Costs, and Environmental Impacts

Radian Corp, Austin, TX

Prepared for

Environmental Protection Agency, Research Triangle Park, NC

Dec 78

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.
EPA 450/3-78-123

2.

3. RECIPIENT'S ACCESSION NO.
PB293014

4. TITLE AND SUBTITLE
Industrial Boilers - Fuel Switching Methods, Costs, and Environmental Impacts

5. REPORT DATE
December, 1978

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)
J. M. Burke and M. D. Matson

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Radian Corporation
8500 Shoal Creek Boulevard
Post Office Box 9948
Austin, Texas 78766

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.
68-02-2608
Assignment No. 37

12. SPONSORING AGENCY NAME AND ADDRESS
Deputy Assistant Administrator for Air Quality Planning and Standards, U. S. Environmental Protection Agency, Office of Air, Noise and Radiation
Research Triangle Park, North Carolina 27711

13. TYPE OF REPORT AND PERIOD COVERED
Final

14. SPONSORING AGENCY CODE
EPA 200/04

15. SUPPLEMENTARY NOTES
This report discusses one issue which could arise in developing emission limits for industrial boilers.

16. ABSTRACT

The potential for existing boilers to switch fuels from natural gas or oil to oil, coal, or a coal derived fuel is examined. Twenty possible fuel switching senarios are identified. The technical aspects of switching fuels, the capital and operating costs and the environmental effects are discussed. The influence of legislation such as the Energy Supply and Environmental Coordination Act of 1974 (ESECA), the Energy Policy and Conservation Act of 1975 (EPCA) and the National Energy Plan was considered. The fuel tax/investment credit program which was part of the proposed National Energy Plan was not passed by Congress in October, 1978. Therefore, the discussion of this program in Section 5 is no longer valid.

15

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
control techniques coal boilers costs fuel oil	air pollution control	13 B

18. DISTRIBUTION STATEMENT Release Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 182
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE A09 - A01

EPA Form 2220-1 (9-73)

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-78-123
December 1978

Air

PB 293014

EPA

Industrial Boilers - Fuel Switching Methods, Costs, and Environmental Impacts

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

Industrial Boilers - Fuel Switching Methods, Costs, and Environmental Impacts

by

J.M. Burke and M.D. Matson

Radian Corporation
8500 Shoal Creek Boulevard
Austin, Texas 78750

Contract No. 68-02-2608

EPA Project Officer: Kenneth R. Woodard
Emission Standards and Engineering Division

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

December 1978

This report has been reviewed by the Emission Standards and Engineering Division of the Office of Air Quality Planning and Standards, EPA, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Environmental Protection Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use. Copies of this report are available through the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, or from National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161.

CONTENTS

List of Figures iv

List of Tables vi

1. Introduction 1
2. Summary 3
3. Conclusions 7
4. Fuel Switching Methods 8
    - Industrial Boilers 8
    - Fuel Switch From Gas to Oil 15
    - Fuel Switch From Gas and Oil to Coal 31
5. Factors Affecting Fuel Switching 112
    - Standard Boilers 113
    - Impact of ESECA and the NEP on Fuel Switching 115
    - Environmental Impact of Fuel Switching 123
    - Relative Costs of Fuel Switching Methods 130
    - Expected Fuel Switches 160

References 169

Appendices

A. Emission Factors for Industrial Boilers 174

B. Sample Combustion Calculation for Natural Gas 176

C. Estimated Costs for Low and Medium-Btu Gas and a Coal-Based Liquid Fuel 181

D. Estimated Coal-Oil Mixture Costs 193

E. Estimated Annual Capital, O&M, and Fuel Costs For Fuel Switching Scenarios 199

F. Estimated Annual Costs for Pollution Control Equipment 220

FIGURES

Number		Page
4-1	Schematic of a water tube boiler	11
4-2	Relative size of a gas-, oil-, and coal-fired boiler with the same capacity	13
4-3	Estimated capital costs of a gas to oil conversion based on new boiler costs ($1978)	24
4-4	Estimated capital costs of a gas to oil conversion based on oil storage costs ($1978)	25
4-5	Estimated operating and maintenance costs for a gas- and oil-fired boiler	26
4-6	A comparison of stoker-, pulverized coal- and gas/oil-fired boiler capital costs (1978$)	41
4-7	Projected capital costs for a stoker-fired boiler	44
4-8	Projected capital costs for a pulverized coal-fired boiler	45
4-9	Estimated operating and maintenance costs for a coal-fired boiler	46
4-10	Comparison of operating and maintenance costs of a gas/oil-fired boiler and a coal-fired boiler	48
4-11	Estimated capital costs for coal handling and storage (1977$)	63
4-12	Estimated costs for ash handling equipment (1977$)	64
4-13	Estimated increase in operating and maintenance costs which results from a switch to coal	66
4-14	Estimated cost of boiler modifications required to fire COM ($1978)	78

FIGURES (Continued)

Number Page

4-15 Estimated capital costs for conversion of a residual oil boiler to COM firing ($1978).......................... 80

4-16 A comparison of COM preparation plant capital costs with the capital cost of a pulverized coal-fired boiler ($1978).. 81

4-17 Estimated operating and maintenance costs for a COM-fired boiler.. 83

4-18 Estimated operating and maintenance costs for a COM preparation plant...................................... 85

4-19 Estimated capital costs of modification to boiler fuel supply system and burners (1978$)......................... 97

4-20 Estimated capital costs for modification of an oil boiler to fire SRC-II ($1978)................................... 107

TABLES

Number Page

2-1 Fuel Switching Scenarios for Three Standard Boilers.......... 5
2-2 Expected Fuel Switches for Three Standard Boilers............ 6
4-1 Relative Volumes of A Gas, Oil and Coal-Fired Boiler With the Same Capacity.. 12
4-2 Recommended Flue Gas Velocities Through Tube Banks as a Function of Fuel Type....................................... 14
4-3 Recommended Tube Spacing as a Function of Fuel Type.......... 16
4-4 Furnace Design Parameters as a Function of Boiler Type....... 17
4-5 Estimated Change in Emissions Which Result From a Gas to Oil Fuel Switch... 27
4-6 A Comparison of Emissions from Oil-Fired Industrial Boilers to "Typical" State Regulations........................... 28
4-7 Available Coal Handling and Storage Equipment............... 35
4-8 Types of Pulverized-Coal Equipment.......................... 39
4-9 Estimated Price Difference Between Coal and Gas/Oil Required for Boiler Replacement to be Economical.................... 42
4-10 Operating and Maintenance Costs for a Coal-Fired Boiler as a Percentage of Annual Costs................................ 43
4-11 A Comparison of Estimated Industrial Coal-Fired Boiler Emissions to Typical State Regulations.................... 49
4-12 Estimated Emission Change Due to Fuel Switching............. 68
4-13 Characteristics of Coal-Oil Mixture Research Projects........ 76
4-14 Comparison of COM Selling Price with Price of Residual Oil... 82

TABLES (Continued)

Number		Page
4-15	Estimated Change in Emissions Which Results When Gas and Oil Boilers Switch to COM Firing........................	86
4-16	A Comparison of Coal-Based Fuel Gas Compositions With the Composition of Natural Gas................................	91
4-17	Relative Volume and Weight of Fuel and Flue Gas From the Combustion of Low-Btu, Medium-Btu and Natural Gas.........	92
4-18	Estimated Performance of Unmodified Gas and Oil Boilers Firing Different Coal-Based Fuel Gases....................	93
4-19	Properties of Typical Distillate and Residual Fuel Oils and Coal-Liquids..	103
4-20	Estimated Emissions Using SRC-II, H-Coal, and EDS Coal-Liquids in Industrial Boilers............................	109
4-21	Estimated Change in Emissions Which Results When Gas/Oil-Fired Boilers Switch to Coal-Liquids.................	110
5-1	Standard Boiler Characteristics................................	114
5-2	Design Parameters for Standard Boilers Subject to Fuel Switching...	116
5-3	Estimated Fuel Costs Through 1990 With and Without Proposed NEP Fuel Taxes.....................................	120
5-4	Annual Fuel Consumption of Standard Boilers..................	122
5-5	Estimated Emissions and Control Requirements for Fuel Switching in a Gas Fired, Fire Tube Boiler...............	124
5-6	Estimated Emissions and Control Requirements for Fuel Switching in a Distillate Oil Fired, Fire Tube Boiler.....	127
5-7	Estimated Emissions and Control Requirements for Fuel Switching in a Residual Oil Fired, Water Tube Boiler......	129
5-8	Summary of Control Requirements for Fuel Switching in Standard Boilers.......................................	131
5-9	Estimated Costs of Coal-Based Fuels..........................	135

TABLES (Continued)

Number Page

5-10 A Comparison of the Annual Costs for a 4.4 MW Natural Gas Fired Boiler Before and After Switching Fuels............ 138

5-11 A Comparison of the Annual Costs for a 4.4 MW Gas Fired Boiler Before and After Switching Fuels.................. 141

5-12 Range of Potnetial Impact From the Fuel Tax/Investment Credit Program on the Annual Costs of a 4.4 MW Gas Fired Boiler.. 143

5-13 A Comparison of the Annual Costs for a 4.4 MW Distillate Oil Fired Boiler Before and After Switching Fuels......... 146

5-14 A Comparison of the Annual Costs for a 4.4 MW Distillate Oil Fired Boiler Before and After Switching Fuels......... 148

5-15 Range of Potential Impact From the Fuel Tax/Investment Credit Program on the Annual Costs of a 4.4 MW Distillate Oil Fired Boiler... 151

5-16 A Comparison of the Annual Costs for a 44 MW Residual Oil Fired Boiler Before and After Switching Fuels............ 154

5-17 A Comparison of the Annual Costs for a 44 MW Residual Oil Fired Boiler Before and After Switching Fuels............ 156

5-18 Range of Potential Impact From the Fuel Tax/Investment Credit Program on the Annual Costs of a 44 MW Residual Oil Fired Boiler... 159

5-19 Expected Fuel Switches for a 4.4 MW Natural Gas-Fired Boiler.. 162

5-20 Design Parameters for a 4.4 MW Natural Gas Fired Boiler After Switching Fuels.................................. 163

5-21 Expected Fuel Switches for a 4.4 MW Distillate Oil Fired Boiler.. 164

5-22 Design Parameters for a 4.4 MW Distillate Oil Fired Boiler After Switching Fuels.................................. 165

5-23 Expected Fuel Switches for a 44 MW Residual Oil Fired Boiler.. 166

5-24 Design Parameters for a 44 MW Residual Oil Fired Boiler After Switching Fuels.................................. 168

SECTION 1
INTRODUCTION

The Clean Air Act Amendments of 1977 require the Environmental Protection Agency to coordinate and lead the development and implementation of regulations to limit air pollution. These regulations include standards of performance for new and modified sources of pollution. Specifically mentioned in the 1977 Clean Air Act Amendments are fossil fuel fired steam generators. Accordingly, the Environmental Protection Agency has undertaken a study of industrial boilers with intent to propose standards of performance based on the results of these studies.

This study was conducted by Radian Corporation to develop background information and data for use by the Emission Standards and Engineering Division of the EPA. Existing industrial boilers were studied to determine the potential for these boilers to become modified sources of pollution. Specifically, the potential for existing boilers to switch fuels from gas or oil to oil, coal, or a coal-based fuel was examined. In order to determine the potential for fuel switching in existing industrial boilers, the technical, economic, environmental, and regulatory aspects of fuel switching were considered.

As part of the EPA's program to develop standards of performance for industrial boilers, seven "standard" or model boilers have been identified as being representative of the existing industrial boiler population. Of these seven, three are either gas or oil fired and these three served as a basis for this study. As a result of an analysis of the technical aspects of switching fuels, potential fuel switching scenarios were determined for the three standard boilers. A total of twenty scenarios were identified and costs were determined for each scenario under several conditions.

Costs were estimated for the fuel switching scenarios without consideration of environmental or energy regulations. Cost estimates were also prepared which consider addition of pollution control equipment and the impact of certain provisions of the National Energy Plan. Based on this series of cost estimates, the impact of environmental and energy regulations on fuel switching in existing industrial boilers was identified. In addition, the most probable fuel switching methods to be employed by existing boilers were determined. And the design parameters of the standard boilers after switching fuels by the most probable methods were estimated. However, the number of boilers which are expected to switch fuels could not be determined. This is because site specific data are required to perform an analysis which can quantify fuel switching in existing industrial boilers, and these data are not available.

SECTION 2

SUMMARY

The objectives of this study were to determine which fuel switching methods existing gas and oil fired boilers will use to switch fuels and to determine the number of existing boilers which will switch fuels by each method. Fuel switching methods were identified and analyzed for technical feasibility. Based on this analysis, potential fuel switching scenarios were developed and the associated costs were estimated. As a result, the expected or most probable fuel switching methods have been identified. In addition, a qualitative analysis of fuel switches in existing boilers was performed. However, due to lack of site specific data, the number of boilers which are expected to switch fuels by each method could not be quantified.

The following six fuel switching methods were identified as possible candidates for use in existing industrial boilers:

1) gas to oil, boiler modification
2) gas/oil to coal, boiler replacement
3) gas/oil to coal, boiler modification
4) gas/oil to coal-oil mixture firing
5) gas/oil to coal-based gas firing
6) gas/oil to coal-based liquid firing

A technical analysis of these fuel switching methods indicated that each one has some potential application to existing industrial boilers. However, boiler modification to switch from gas/oil to coal firing does not appear feasible except in cases where the boiler was originally designed to fire coal.

The six fuel switching methods were then applied to three standard boilers. These boilers are:

1) 4.4 MW, natural gas fired, fire tube boiler
2) 4.4 MW, distillate oil fired, fire tube boiler
3) 44 MW, residual oil fired, fire tube boiler

Based on the technical analysis of fuel switching methods, it was determined that some fuel switching methods were not applicable to the standard boilers. By considering various fuel characteristics, a total of twenty fuel switching scenarios was identified (Table 2-1). As shown, the natural gas and distillate oil boilers have a more limited number of fuel switching options. This is because these boilers cannot practically burn any fuel containing ash (EG-016). The residual oil fired boiler on the other hand, is a conservatively designed unit and thus has more flexibility in the type of fuels which can be burned.

Annual costs were estimated for each of the twenty fuel switching scenarios presented in Table 2-1. Costs were determined for three cases. In the first case, costs were estimated without consideration of any regulations. This determined "base-line" costs. In the second case, costs estimates included changes for pollution control equipment. For the third case, the range of impact from provisions of the National Energy Plan were determined. Based on these costs estimates, expected fuel switches were determined.

Table 2-2 presents the fuel switching methods which are expected to be employed by existing boilers similar to the three standard boilers. As shown, small gas and oil fired units are not expected to switch fuels except under the maximum impact of the National Energy Plan. The residual oil fired boiler is expected to switch fuel to low-sulfur coal firing under all conditions. However, because of the low coal prices used in the cost analysis, the number of fuel switches to coal will be limited.

TABLE 2-1. FUEL SWITCHING SCENARIOS FOR THREE STANDARD BOILERS

4.4 MW Natural Gas Fired Fire Tube Boiler	4.4 MW Distillate Oil Fired Fire Tube Boiler	44 MW Residual Oil Fired Water Tube Boiler
Natural gas to distillate oil/ boiler modification	Distillate oil to low-Btu gas/ boiler modification	Residual oil to low-Btu gas/ boiler modification
Natural gas to low-Btu gas/ boiler modification	Distillate oil to medium-Btu gas/boiler modification	Residual oil to medium-Btu gas/ boiler modification
Natural gas to medium-Btu gas/ boiler modification	Distillate oil to high-sulfur coal/boiler replacement	Residual oil to COM 1[1]/boiler modification
Natural gas to high-sulfur coal/boiler replacement	Distillate oil to low-sulfur coal/boiler replacement	Residual oil to COM 2[1]/boiler modification
Natural gas to low-sulfur eastern coal/boiler replacement	Distillate oil to low-sulfur western coal/boiler replacement	Residual oil to COM 3[1]/boiler modification
Natural gas to low-sulfur western coal/boiler replacement		Residual oil to coal-based liquid coal/boiler modification
		Residual oil to high-sulfur coal/boiler replacement
		Residual oil to low-sulfur eastern coal/boiler replacement
		Residual oil to low-sulfur western coal/boiler replacement

---

[1] Analyses of coal-oil mixtures are presented in Table 4-15.

TABLE 2-2. EXPECTED FUEL SWITCHES FOR THREE STANDARD BOILERS

Basis	Standard Boiler 4.4 MW Natural Gas Fired Fire Tube Boiler	 4.4 MW Distillate Oil Fired Fire Tube Boiler	 44 MW Residual Oil Fired Water Tube Boiler
No regulations	None	None	Low-sulfur western coal
Typical State Regulations	None	None	Low-sulfur western coal
Minimum Impact of NEP	None	None	Low-sulfur western coal
Maximum Impact of NEP	None	Medium-Btu gas	Low-sulfur western coal

SECTION 3

CONCLUSIONS

The following major conclusions were reached as a result of this study:

1) Small (4.4 MW) existing gas and distillate oil fired boilers are not expected to switch fuels unless the supply of gas and oil becomes insecure.

2) If small gas and distillate oil fired boilers do switch fuels, boiler replacement to permit coal firing is the most probable fuel switching method. Modification of the boiler to permit medium-Btu gas firing is also expected but because no medium-Btu gas production facilities exist and the projected production of medium-Btu gas is expected to be limited, this fuel switching method will not have a significant impact on existing boilers.

3) Large (44 MW) residual oil fired boilers are expected to switch fuels. However, the extent of fuel switching will be limited.

4) A switch from residual oil to coal by boiler replacement is the most likely switch. However, it appears that this will only occur if the existing boiler is close to retirement

5) A switch to coal-oil mixture firing is a definite possibility for residual oil fired boilers if the technology becomes developed and its reliability can be demonstrated.

6) No quantitative estimate of the number of boilers which will switch fuels can be made. This is because data on the number of boilers in a particular location are required to assess the impact of the fuel tax/investment credit portion of the national energy plan on fuel switching. However, based on an analysis of the range of the impact from the NEP, the extent of fuel switching in existing boilers is expected to be very limited. And the the most likely fuel switching method is boiler replacement to permit coal firing.

SECTION 4

FUEL SWITCHING METHODS

Dwindling supplies of natural gas and oil coupled with regulations aimed at decreasing U.S. dependence on foreign oil have changed many industries outlook on the type of fuels they should use in their steam generators. In fact, a drive toward increased use of coal, an abundant resource in the U.S., has become national policy. Unfortunately, most steam generators in operation were designed for one specific fuel and to switch to a different fuel can prove exceedingly difficult and expensive. This is especially true in the case of a switch from gas or oil to coal.

Many factors must be considered and many uncertainties surround a fuel switch. This section presents a discussion of the considerations for switching fuels in industrial boilers and a description of the various methods which can be used to switch fuels. Included as background are a description of the types of industrial boilers in use and design considerations for these boilers.

4.1 INDUSTRIAL BOILERS

Industrial boilers range in capacity from 0.1 to over 450 MW[1] (0.4 x 10^6 to 1500 x 10^6 Btu/hr). In general, these boilers fire either gas, oil, or coal. And some have been designed to fire two or even all three of these fuels. In addition, some industrial boilers are capable of firing waste fuels such as bark, saw dust, coke oven gas, coffee grounds, etc.

---

[1] The symbol MW refers to heat input to the boiler.

4.1.1 Description

Industrial boilers can be classified as sectional, fire tube, and water tube. Sectional boilers are small units with an average capacity of 7.3 x 10^{-2} MW (0.25 x 10^6 Btu/hr). These units comprise 22.5 percent of the total industrial boiler capacity in the United States and are only suitable for very low pressures (0.21 MPa - 30 psia). Consequently, they are frequently used as water heaters or in space heating applications.

Because of their small size, sectional boilers are not suitable candidates for fuel switching. Therefore, no further consideration will be given to these units.

Fire tube boilers represent 18.5 percent of the U.S. industrial boiler capacity. These boilers usually are smaller than 9 MW (30 x 10^6 Btu/hr) and they are only capable of firing gas or oil (PE-346)(EG-016). In a fire tube boiler, hot combustion gases are circulated through metal tubes which are immersed in boiler feedwater. Heat is transferred by convection from the combustion gases to the water, and steam or hot water is produced.

The principal advantage of a fire tube boiler is its compact design. These boilers are shipped preassembled and ready to be connected. They have the highest capacity per unit volume of furnace of any boiler and they are suited for applications where space is limited.

Water tube boilers represent 59 percent of the U.S. industrial boiler capacity. They have capacities over 450 MW (1500 x 10^6 Btu/hr), but more than 90 percent of these boilers are smaller than 30 MW (100 x 10^6 Btu/hr) (PE-346).

There are two types of water tube boilers: packaged and field erected. Packaged boilers are assembled in a shop and shipped (usually by rail) to the location where they will be used. Because of the legal and practical limitations of rail shipping, package boilers are small (capacities less than 15 MW - 50 x 10^6 Btu/hr). The advantage of these boilers is that they are less expensive than the field erected type.

Field erected boilers are units which are assembled at the location where they will be used. These boilers are usually large, with capacities ranging from 15 MW to over 450 MW (50 x 10^6 to over 1500 x 10^6 Btu/hr). In general, most pulverized coal, waste fuel, and larger (greater than 15 MW - 50 x 10^6 Btu/hr) gas, oil, and stoker-fired boilers are field erected (SC-402).

In a water tube boiler, combustion takes place in a furnace whose walls are lined with metal tubes containing boiler feedwater (Figure 4-1). This furnace is known as the "radiant" section of the boiler because heat is transferred from the combustion gases to the water by radiation.

Combustion gases are cooled from 1650°C (3000 °F) to below 1100°C (2000°F) in the furnace. These gases then flow to the "convective" section of the boiler. There, the gases pass through banks of tubes which are filled with water or steam. And heat is transferred from the gases by convection. Exit temperature from this section of the boiler is approximately 370°C (700°F). Combustion gases then flow to an air preheater where they are further cooled as combustion air is heated. The gases may also be processed in one of several pollution control systems to remove particulates, sulfur oxides, etc.

4.1.2 Boiler Design Considerations

The most important influence on boiler design is the fuel to be burned. This will determine the size of the boiler and the characteristics of the heat transfer surfaces in both the "radiant" and "convective" sections of the boiler. The following discussion examines how the properties of gas, oil, and coal influence boiler design.

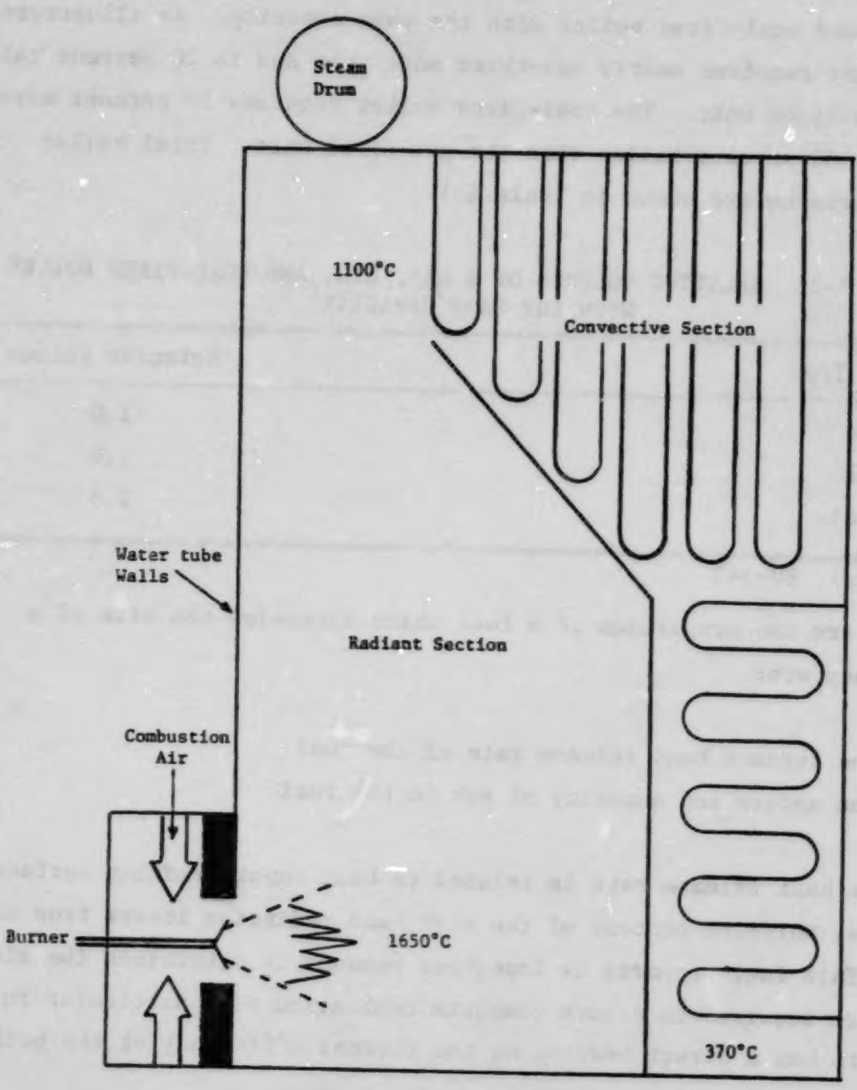

Steam Drum
1100°C
Convective Section
Water tube Walls
Radiant Section
Combustion Air
Burner
1650°C
370°C

Figure 4-1. Schematic of a water tube boiler.

Perhaps the most obvious impact of various fuels on boiler design is the difference in boiler sizes. Figure 4-2 shows the relative size of a gas-, oil-, and coal-fired boiler with the same capacity. As illustrated, the oil boiler requires nearly one-third more area and is 20 percent taller than the gas-fired unit. The coal-fired boiler requires 50 percent more area and is 60 percent taller than the gas-fired unit. Total boiler volume comparisons are shown in Table 4-1.

TABLE 4-1. RELATIVE VOLUMES OF A GAS, OIL, AND COAL-FIRED BOILER WITH THE SAME CAPACITY[1]

Boiler Type	Relative Volume
Gas	1.0
Oil	1.6
Coal	2.5

[1] Source: BU-343

There are two properties of a fuel which determine the size of a boiler. They are:

1) The furnace heat release rate of the fuel
2) The nature and quantity of ash in the fuel

The furnace heat release rate is related to heat input, radiant surface in the furnace, moisture content of the fuel, and radiation losses from the furnace. This fuel property is important because it determines the minimum furnace size required to assure complete combustion of a particular fuel. This in turn has a direct bearing on the thermal efficiency of the boiler.

Ash is an important fuel property for several reasons. First, fuels with ash must have furnaces which are larger than the minimum determined by the heat release rate. This is because ash becomes molten at furnace temperatures. If the furnace is too small, molten ash or "slag" can deposit

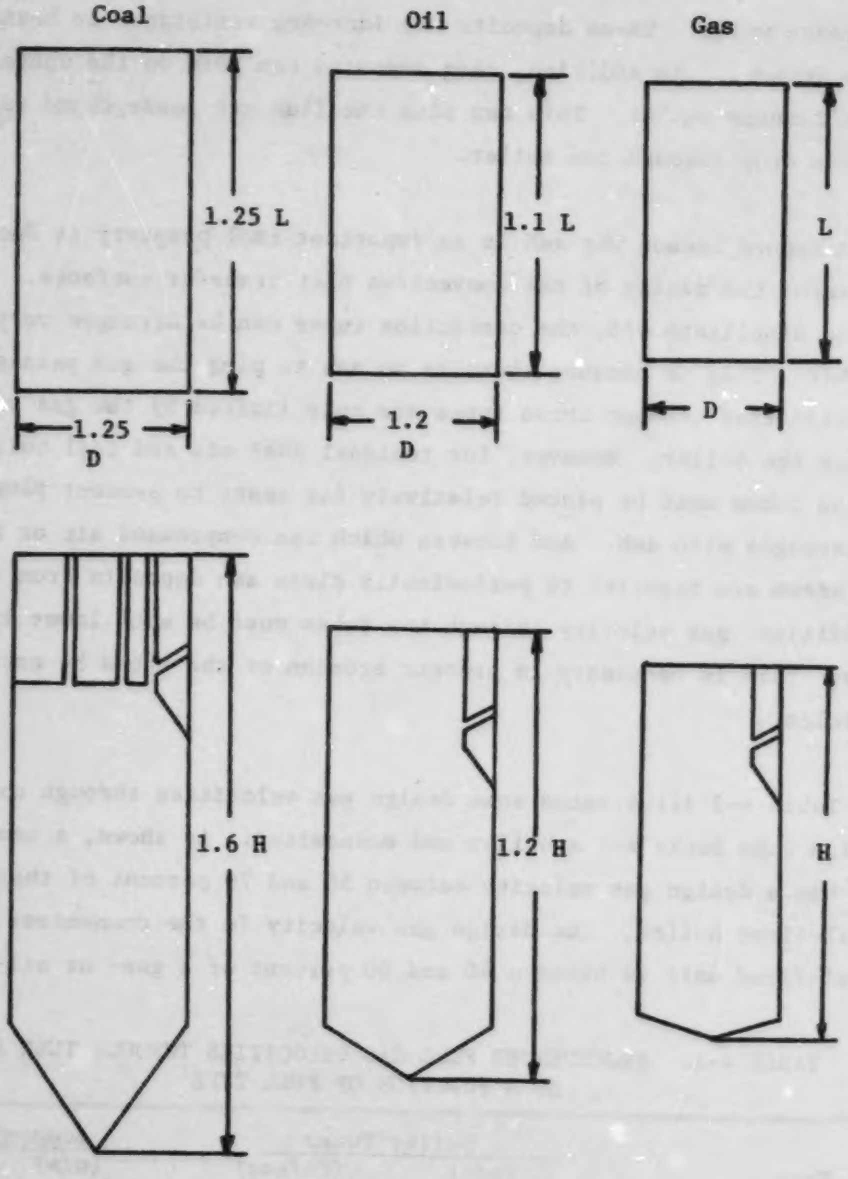

Coal
Oil
Gas
1.25 L
1.1 L
L
1.25 D
1.2 D
D
1.6 H
1.2 H
H

Figure 4-2. Relative size of a gas-, oil-, and coal-fired boiler with the same capacity (BU-343).

on furnace walls. These deposits may increase resistance to heat transfer in the furnace. In addition, slag deposits can form on the convection tubes at the furnace outlet. This can plug the flue gas passage and raise the gas pressure drop through the boiler.

A second reason why ash is an important fuel property is because it influences the design of the convective heat transfer surfaces. For natural gas and distillate oil, the convection tubes can be arranged very close together. This is because there is no ash to plug the gas passages. Design gas velocities through these tubes are only limited by the gas pressure drop through the boiler. However, for residual fuel oil and coal boilers, convection tubes must be placed relatively far apart to prevent plugging of gas passages with ash. And blowers which use compressed air or high pressure steam are required to periodically clean ash deposits from the tubes. In addition, gas velocity through the tubes must be much lower in coal-fired units. This is necessary to prevent erosion of the tubes by entrained ash particles.

Table 4-2 illustrates some design gas velocities through convective section tube banks for a boiler and economizer. As shown, a coal-fired unit has a design gas velocity between 50 and 70 percent of that in a gas- or oil-fired boiler. The design gas velocity in the economizer section of a coal-fired unit is between 40 and 60 percent of a gas- or oil-fired unit.

TABLE 4-2. RECOMMENDED FLUE GAS VELOCITIES THROUGH TUBE BANKS AS A FUNCTION OF FUEL TYPE[1]

	Boiler Tubes		Economizer Tubes	
Fuel Type	(m/s)	(ft/sec)	(m/s)	(ft/sec)
Natural Gas	30.5	100	30.5	100
Distillate Oil	30.5	100	30.5	100
Residual Oil	30.5	100	30.5	100
Coal				
low ash	19.8-21.3	65-70	15.2-18.3	50-60
high ash	15.2	50	12.2-15.2	40-50

[1] Source: SC-402

Table 4-3 shows some recommended tube spacings for a superheater, boiler, and economizer. As illustrated, the widest variation as a function of fuels occurs in the superheater. Design spacing for a residual oil superheater is up to three times that of a gas or distillate oil unit while tube spacing in a coal-fired superheater ranges from four to eight times the spacing in gas and distillate oil units.

Constituents of fuel ash can also impact the materials of construction used in a boiler. The presence of compounds such as sodium, vanadium, and sulfur in ash can result in corrosion. This corrosion may occur in both the high- and low-temperature regions of the boiler. As a result, construction materials used in the boiler must be selected to resist corrosion.

Table 4-4 presents some typical furnace design parameters. The value of these parameters is determined by the two fuel properties: furnace heat release rate and the nature and quantity of ash. As shown, natural gas and oil boilers have equal values for these parameters. But coal boilers have a much lower design value (approximately 50 percent lower). This means that, for a given capacity, a coal-fired boiler requires approximately twice the radiant surface and twice the furnace volume of a gas- or oil-fired boiler. Conversely, for a given size, a coal-fired boiler will have about one-half the steam capacity of a gas- or oil-fired boiler.

4.2 FUEL SWITCH FROM GAS TO OIL

In recent years, industrial users of natural gas have found that their supply of gas has become insecure. In addition, regulations have been enacted which require a reduction in natural gas consumption by industrial steam generators. As a result, many industrial boiler operators are looking for an alternate fuel source. Oil is a fuel which can be substituted for natural gas in an existing boiler.

TABLE 4-3. RECOMMENDED TUBE SPACING AS A FUNCTION OF FUEL TYPE[1,2]

	Superheater				Boiler				Economizer	
	Front		Rear		Front		Rear			
Fuel Type	(cm)	(in)	(cm)	(in)	(cm)	(in)	(cm)	(in)	(cm)	(in)
Natural Gas	5	2	5	2	3	1	3	1	3	1
Distillate Oil	5	2	5	2	3	1	3	1	3	1
Residual Oil	10-15	4-6	5	2	4	1.5	3	1	3	1
Coal										
low ash	20	8	8-15	3-6	4	1.5	3	1	3	1
high ash	25-41	10-16	10-15	4-6	5	2	3-5	1-2	3	1

---

[1] Source: SC-402

[2] Tube spacing perpendicular to flue gas flow

TABLE 4-4. FURNACE DESIGN PARAMETERS AS A FUNCTION OF BOILER TYPE[1]

Boiler Type	Heat released per unit area of effective radiant surface ($J/m^2 \cdot s$)	Heat released per unit area of effective radiant surface (10^3Btu/hr·ft^2)	Heat released per unit volume of furnace ($J/m^3 \cdot s$)	Heat released per unit volume of furnace (10^3Btu/hr·ft^3)
Packaged, natural gas	630	200	520-1030	50-100
Field erected, natural gas	630	200	260-520	25-50
Packaged, oil-fired	630	200	520-1030	50-100
Field erected, oil-fired	630	200	260-520	25-50
Spreader stoker, coal-fired	220-380	70-120	150-230	15-22
Pulverized, coal-fired	250-410	80-130	260-310	25-30

---

[1] Source: SC-402

4.2.1 Boiler Modification - Gas to Oil

One method of reducing natural gas consumption in existing gas-fired boilers is to modify these boilers for oil-firing. Oil, unlike coal, has properties similar to natural gas, and only minor modifications are required to convert an existing gas boiler to oil-firing. This is especially true in the case of a conversion from gas to distillate oil.

Unfortunately, the supply of oil is as unsure as the supply of natural gas, and any conversion represents a temporary solution at best. However, it does appear that some gas to oil conversions will take place.

The following discussion examines the technical considerations of a conversion from gas to oil. In addition, an estimate of the costs to perform the required boiler modifications and an estimate of the change in emissions are presented.

4.2.1.1 Process Description - Boiler Modification/Gas to Oil--

There are two possible types of gas to oil boiler conversions. The first is a switch to distillate oil and the second is a switch to residual oil. Because distillate oil is a very clean fuel, it can be burned in most existing gas boilers without a significant impact. However, residual oil is a fuel which contains significant quantities of both ash and sulfur. As a result, combustion of residual oil in an existing gas-fired boiler presents a more significant problem.

The extent to which an existing gas boiler must be modified to be capable of firing oil will depend on the original design, and each boiler conversion will be very site specific. However, there are some general considerations which can be examined. They are:

1) Furnace Size
2) Oil Storage Requirements

3) Boiler Modifications

4) Pollution Control Requirements

The following discussion examines each of these considerations in detail.

Furnace size--Oil has a higher furnace heat release rate than natural gas. This is particularly true in the case of residual oil. As a result, for a given capacity, more heat will be absorbed in an oil-fired boiler's furnace than in a gas-fired furnace.

Heat release is an important consideration when converting a gas boiler to oil firing. Most boilers operate with a heat release rate which provides some margin of safety. The extent to which a gas boiler that switches to oil will be derated depends on how large this margin is. If the gas boiler was operating with a high furnace heat release rate (relative to good design practices), some derating of the boiler may be required when converting to oil. But, if the boiler was operating with a large safety margin, no derating may occur. Derating will be necessary to maintain a safe heat release rate. This is required to prevent hot spots on the furnace walls, and in the case of oil with a high ash content, to prevent slag deposits from forming in the furnace.

Oil storage--Possibly one of the major expenditures which will be associated with a conversion from gas to oil will be the cost of installing oil storage tanks. Good design practices require a 10 day storage capacity. And the space required for oil storage may present a problem at some industrial locations. However, storage facilities can be installed at a remote location and the oil can be pumped to the boiler.

Boiler modification--The first modification which will be required when converting from gas to oil is the installation of fuel supply lines and oil burners. Since this equipment is similar for both gas- and oil-firing, its installation should not present a problem.

Because natural gas and oil burn with different flames and have different furnace heat release rates, boilers designed to burn these fuels are also different, and conversion of a gas boiler to oil-firing may require modification of boiler internals.

The presence of ash in residual oil will have a significant impact on boiler performance. Ash can deposit on superheater and reheater tubes which will reduce heat transfer. Coupled with increased heat absorption in the furnace, this reduces heat absorption in the convective section of the boiler. As a result, design steam temperatures may not be obtainable, even at full load.

In order to obtain design steam temperatures, the following modifications may be required.

1) The addition of heat transfer surface to the superheater or reheater.

2) The removal of heating surface from the furnace. This can be done by addition of a dividing wall which effectively reduces the size of the furnace.

Unfortunately, space or other physical limitations may prevent making the heating surface changes needed to permit the boiler to operate at design steam conditions.

In addition to depositing on superheater and reheater tubes, ash can deposit in the economizer and air preheater. This could result in plugging of the flue gas passage. Therefore, soot blowers may be required to periodically remove any ash deposits.

Modification of existing fans may be required in a gas to oil conversion. The pressure drop through the boiler will increase and a check must be made to determine if existing fans are capable of supplying sufficient combustion air for oil-firing. Generally, existing fans will be suitable, although the margin of capacity will be reduced.

Modifications of the economizer and air preheater may also be required when converting from gas to oil. If the existing boiler has a finned-tube economizer, the space between the fins can plug with ash. This will increase gas pressure drop and reduce heat transfer in the economizer. In order to avoid these problems, a bare-tube economizer should be installed. The new economizer will require more tubes for equivalent heat transfer surface area and, therefore, will require more space.

If the existing gas-fired boiler has a regenerative air preheater, the heating surface at the cold end may need to be replaced to prevent plugging with ash. In addition, the metal temperature required to prevent acid dew-point corrosion must be maintained. This may require addition of a steam coil for heating the entering air, adding a system for air recirculation from the air preheater outlet to the forced draft fan inlet, or removing some air preheater surface to increase the temperature of the exit flue gas.

Pollution control--A fuel switch from natural gas to distillate oil will not result in a significant change in emissions. However, combustion of residual oil may. The exact impact of residual oil firing will depend on the fuel properties. Particulate control equipment may be required if fuel ash content is high and some sulfur dioxide removal may also be necessary, depending on the sulfur content of the fuel.

Estimated emission changes which result from switching to oil are presented in section 4.2.1.3. In addition, a brief discussion of applicable pollution controls is presented.

4.2.1.2 Costs of Boiler Modification - Gas to Oil--

Converting an existing boiler from gas- to oil-firing is feasible, but only at the expense of outage time and money. The following discussion examines the capital and operating costs of a gas to oil conversion.

Capital costs--No detailed capital cost estimates have been published for converting a gas boiler to oil-firing. However, as a general estimate, one study indicated that a gas to oil conversion would require approximately three weeks of downtime and would cost approximately ten percent of the cost of a new gas/oil-fired boiler (SC-402). Figure 4-3 presents capital costs for a gas to oil conversion based on this estimate. However, these costs do not include the costs which result from the outage time required to complete the conversion.

Another estimate of gas to oil conversion capital costs can be obtained by examining the components of boiler cost which are associated with the conversion. For example, oil storage and handling costs for a converted gas boiler should be identical to those for a new oil boiler. In addition, these costs represent the major cost of a gas to oil conversion. By assuming oil storage and handling costs represent 75 percent of gas to oil conversion costs, total capital costs can be estimated. Figure 4-4 presents estimated conversion costs based on this assumption. The costs presented in Figure 4-4 represent 15 to 20 percent of new boiler costs.

Based on the cost data in Figures 4-3 and 4-4, it appears that modifications required to convert an existing gas boiler to oil-firing will have a capital cost of less than 25 percent of the capital costs of a new boiler. However, these costs do not include expenses associated with outage time required for completion of boiler modifications. These expenses will be very site specific and they may actually be eliminated if spare steam generating capacity is available.

Operating and maintenance costs[1]--The operating and maintenance costs (O&M) for gas and oil boilers are nearly identical, and very little change should occur after a conversion from gas to oil. In fact, gas and oil O&M

---

[1] Operating and maintenance costs do not include fuel costs.

costs are so close that most cost estimators present only one estimate for both gas- and oil-fired units (EN-761).

Figure 4-5 presents estimated O&M costs for a gas and oil-fired boiler. As shown, these costs are relatively insensitive to boiler size below 30 MW (100×10^6 Btu/hr). However, above 30 MW, these costs rise more rapidly. This behavior is probably due to the fact that a base labor force is required to operate a boiler plant regardless of size. At 30 MW, the labor requirements begin to increase exponentially with boiler size.

4.2.1.3 Environmental Impact--

Conversion of a gas-fired boiler to oil-firing may result in an increase in emissions. If the conversion is from gas to distillate oil, the change in emissions will be minimal, but if the conversion is from gas to residual oil, significant increases in nitrogen oxide and sulfur dioxide emissions may occur. The following discussion presents an estimate of the change in emissions which result when an industrial boiler switches from gas to oil. In addition, applicable emission control techniques are identified.

Estimated emissions--The estimated change in emissions which results when a gas boiler is converted to oil firing is presented in Table 4-5. Estimates are included for conversion from gas to both distillate and residual oil. As shown in Table 4-5, sulfur dioxide emissions increase somewhat when a gas boiler is converted to distillate oil-firing. Emissions of other criteria pollutants do not change markedly.

The conversion from gas to residual oil results in a significant increase in sulfur dioxide emissions and a tripling in the emissions of nitrogen oxides. Again, emission rates of other criteria pollutants do not change significantly.

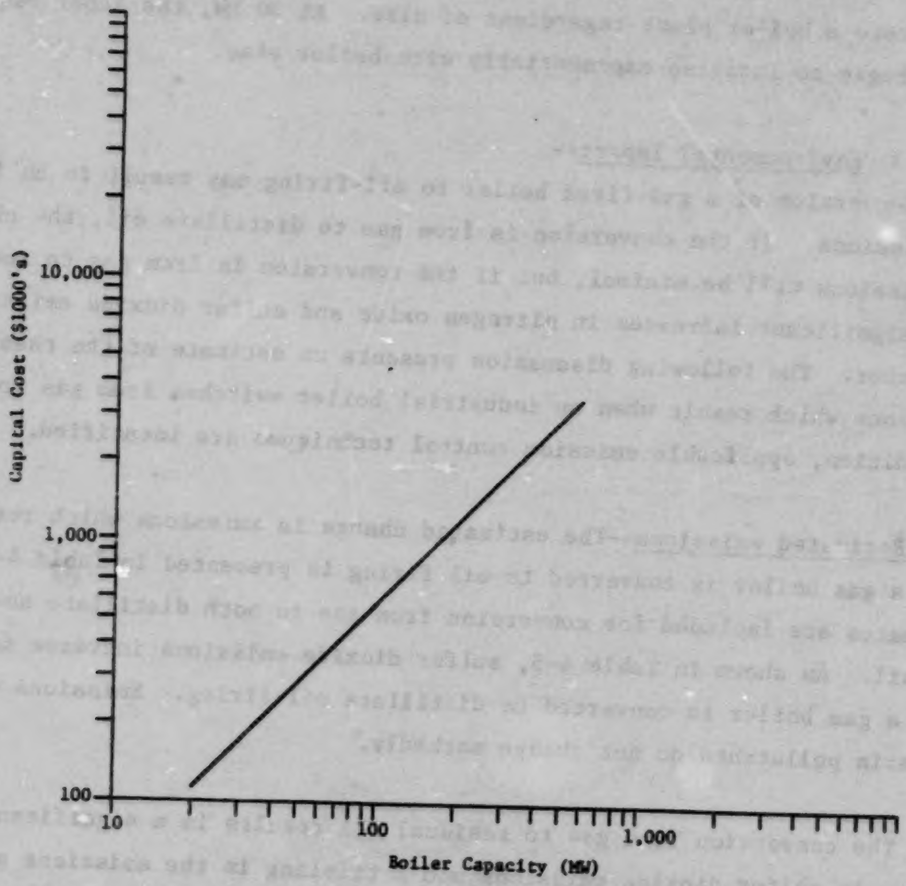


Figure 4-3. Estimated capital costs of a gas to oil conversion based on new boiler costs ($1978).
Source: (EN-761), (SC-402)

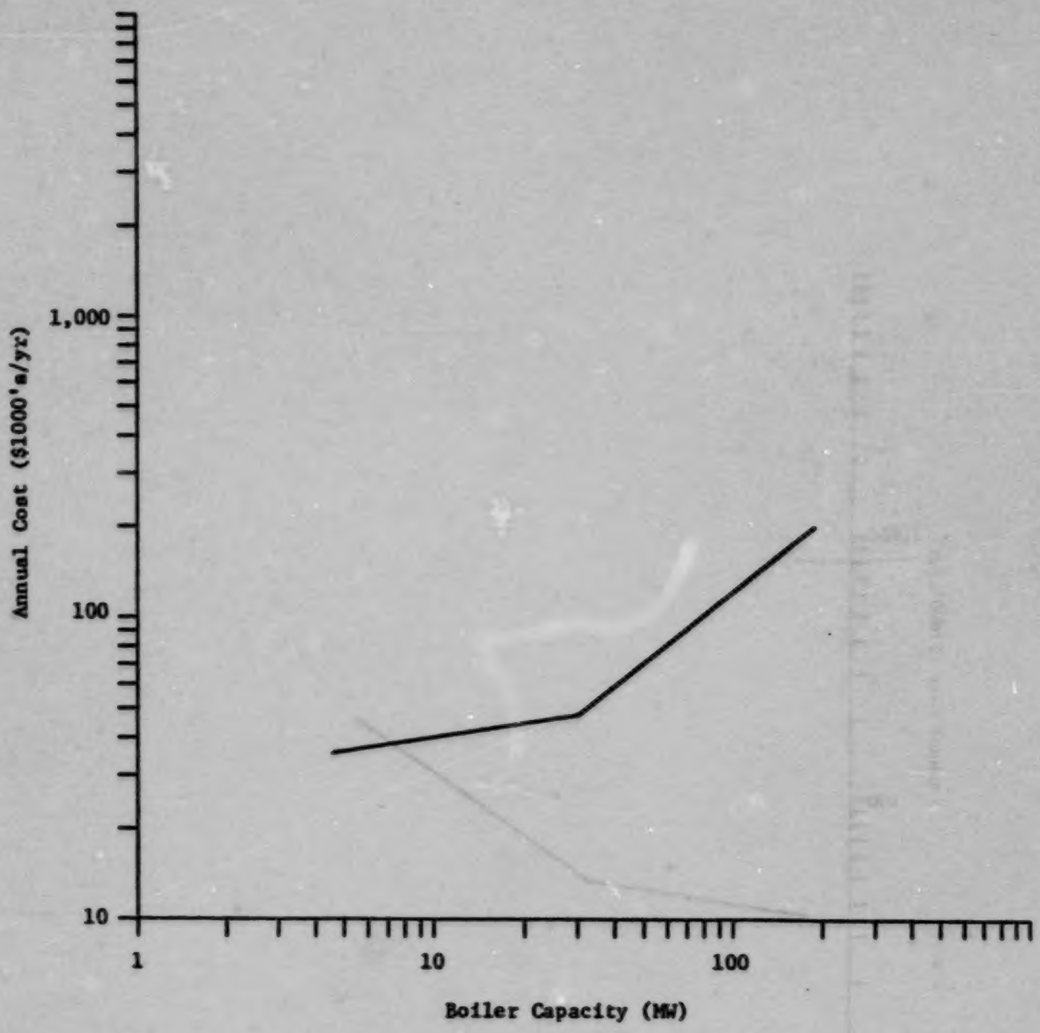


Figure 4-4. Estimated capital costs of a gas to oil conversion based on oil storage costs ($1978).

Source: (IC-005)

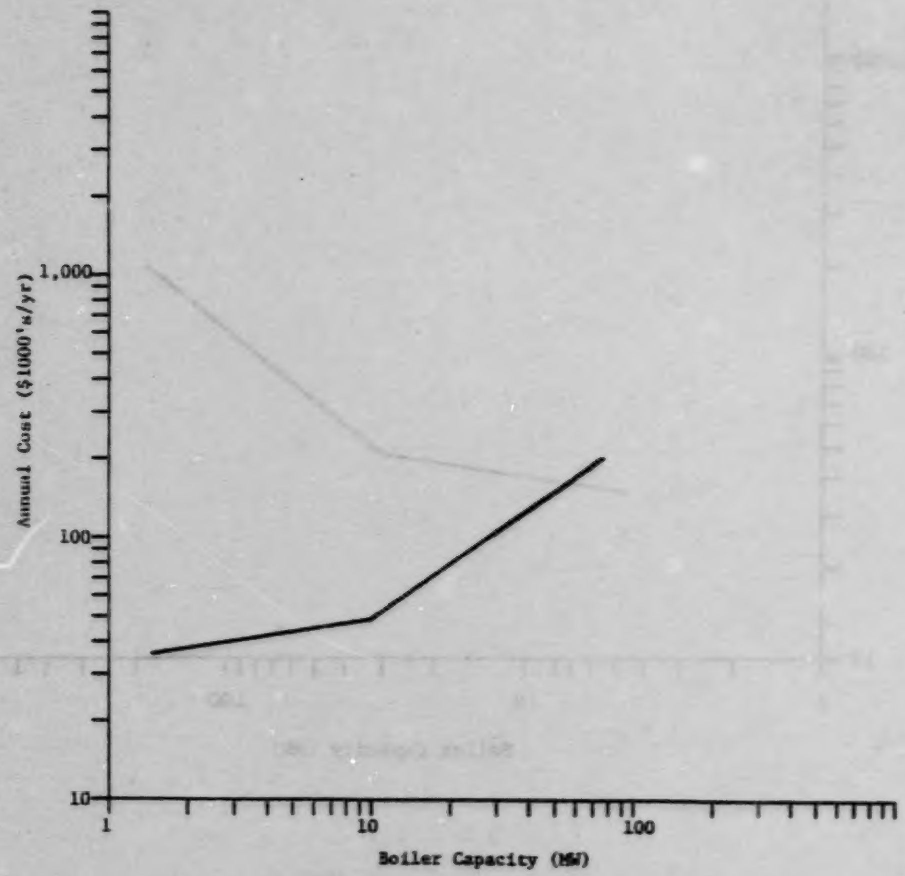


Figure 4-5. Estimated operating and maintenance costs for a gas- and oil-fired boiler.
Load Factor: (4000 hrs/yr at 100 percent capacity)
Source: EN-761

TABLE 4-5. ESTIMATED CHANGE IN EMISSIONS WHICH RESULTS FROM A GAS TO OIL FUEL SWITCH[1]

Pollutant	Change in Emission Rate			
	Gas to distillate oil[2]		Gas to residual oil[2]	
	ng/J	lb/10^6 Btu	ng/J	lb/10^6 Btu
Particulates	7.7	1.8×10^{-2}	37.4	8.7×10^{-2}
Sulfur dioxide	215.0	0.5	1332.8	3.1
Nitrogen oxides as NO_2	43.0	0.1	86.0	0.2
Carbon Monoxide	8.2	1.9×10^{-2}	8.2	1.9×10^{-2}
Hydrocarbons as CH_4	1.8	4.2×10^{-3}	1.8	4.2×10^{-3}

---

[1] Emission rates were calculated based on emission factors supplied by PEDCo (PE-348).

[2] Fuel analyses are:

	Natural Gas	Distillate Oil	Residual Oil
Sulfur	Trace	0.5 percent	3.0 percent
Ash	Trace	Trace	0.1 percent
HHV	37.3 (MJ/m^3)	38.8 (MJ/ℓ)	41.8 (MJ/ℓ)

TABLE 4-6. A COMPARISON OF EMISSIONS FROM OIL-FIRED INDUSTRIAL BOILERS TO "TYPICAL" STATE REGULATIONS[1]

Pollutant	Emission rate					
	Distillate oil		Residual oil			
	ng/J	lb/10^6 Btu	ng/J	lb/10^6 Btu	ng/J	lb/10^6 Btu
Particulates	9.0	2.1×10^{-2}	38.7	9.0×10^{-2}	43.0	0.1
Sulfur dioxide	215.0	0.5	1332.8	3.1	687.8	1.6
Nitrogen oxides as NO_2	86.0	0.2	133.3	0.31	129.0	0.3
Carbon monoxide	15.5	3.6×10^{-2}	15.5	3.6×10^{-2}	-	-
Hydrocarbons as CH_4	3.1	7.2×10^{-3}	3.1	7.2×10^{-3}	-	-

[1] Source: (PE-348)

[2] Fuel analyses are:

	Distillate Oil	Residual Oil
Sulfur	0.5 percent	3.0 percent
Ash	Trace	0.1 percent
HHV	38.8 (MJ/ℓ)	41.8 (MJ/ℓ)

Table 4-6 compares emissions from distillate and residual oil boilers with "typical" state regulations. These "typical" regulations were identified by PEDCo Environmental Specialists as representative of all regulations (GI-155). Comparison of typical state regulations with estimated emissions indicates the severity of the emission increase which results from a gas to oil fuel switch. As shown, conversion to distillate oil will not result in any emission rates which are higher than those allowed by the typical regulations but conversion from gas to residual oil results in emission rates of sulfur dioxide and nitrogen oxides which are above the typical regulations.

Pollution control equipment--A detailed examination of pollution control equipment is being prepared as part of the study to develop background information for industrial boiler NSPS. The following discussion briefly examines the applicability of available pollution control technology to a gas-fired boiler which has been converted to oil.

Particulate control - It does not appear that particulate control equipment will be required by boilers which convert from gas to distillate oil, and these controls may not be needed on gas boilers which convert to low-ash residual oil. Because an existing gas-fired boiler does not have particulate control equipment, it is unlikely that space is available for installation of such equipment. It appears likely that before particulate control equipment would be retrofitted to a gas-fired boiler, a supply of low-ash oil would be obtained.

Sulfur dioxide control - Flue gas desulfurization (FGD) is the principal control technique for removing sulfur dioxide from boiler flue gases. However, in the case of residual oil, it is possible to treat the fuel prior to combustion to remove sulfur. In a situation where an existing gas-fired boiler requires SO_2 control after conversion, low sulfur fuel oil will probably be used to limit SO_2 emissions.

The difficulty of retrofitting an FGD system to an existing boiler, coupled with the increase in operating costs, the potential for a decrease in overall system reliability and the need to dispose of by-product or waste material produced by the FGD system will definitely limit the use of FGD on converted gas boilers.

Nitrogen oxide control - There are two basic methods for controlling nitrogen oxide emissions from industrial boilers. They are:

1) Combustion Modification
2) Flue Gas Treatment (FGT)

Combustion modifications limit NO_x emissions by limiting the formation of NO_x in the boiler. Flue gas treatment limits NO_x emissions by removing it from the flue gas after it has been formed.

Based on the emission estimates presented in Table 4-6, it appears that only a slight reduction in NO_x emissions may be required by a boiler which has converted from gas to oil. Combustion modifications appear best suited for obtaining this reduction.

In general, combustion modifications are capable of reducing NO_x emissions from a boiler by 30 to 50 percent. They could easily be incorporated into the boiler modifications when the unit is converted from gas to oil.

Flue gas treatment cannot be widely used in a retrofit application due to space considerations. In addition, FGT technology has not been demonstrated, and the cost of applying FGT is significantly higher than the cost of combustion modifications.

4.3 FUEL SWITCH FROM GAS AND OIL TO COAL

Operators of gas- and oil-fired industrial steam generators can switch to coal as a fuel by several methods. These switching methods fall into two categories. The first is direct combustion of coal. Switching methods in this category include:

1) Replacement of an existing gas- or oil-fired boiler with a new coal-fired unit. This could include fluidized bed combustion of coal when the technology becomes developed.
2) Modification of an existing gas- or oil-fired boiler to permit direct combustion of coal.
3) Modification of an existing gas- or oil-fired boiler to permit combustion of a coal-oil slurry.

The second category of switching methods is conversion of coal. Switching methods in this category include:

1) Gasification of coal to produce a fuel which can be burned in an existing gas- or oil-fired unit.
2) Liquefaction of coal to produce a fuel which can be burned in an existing gas- or oil-fired unit.

There are many factors which must be considered when examining the possibility of switching to coal. The most important are:

1) Availability of Coal - Is the potential coal user located in an area which has a supply of coal available? Are there transportation facilities to deliver coal to the users plant site? It is assumed for the discussion in Section 4.0 that coal is available.
2) Handling and Storage - If coal is available, it is still necessary to unload, transport, and store the coal within the plant. Is there space available to install coal handling and storage equipment?
3) Equipment - Is it technically and physically possible to install the equipment required to burn coal? This includes either the required boiler modifications or the construction of a coal conversion facility.

4) Pollution Control - The direct combustion of coal can result in increased emissions of particulates, sulfur dioxides, and other pollutants. In addition, coal conversion facilities have the potential to emit pollutants from various process steps. Control equipment may be required to prevent these emissions.

5) Ash Disposal - All coal contains noncombustible material known as ash. Whether direct coal combustion or coal conversion is used as a switching method, an ash waste stream will be produced. The equipment required to handle this ash and the space to safely dispose of it must be available.

6) Costs - The costs of conversion must be outweighed by the costs of continuing to burn natural gas or oil. This cost may be due to fuel price differential or it may be associated with lost production due to shortages of natural gas and oil.

4.3.1 Boiler Replacement

One method to switch from firing gas/oil to coal in an industrial boiler is to replace an existing gas/oil-fired boiler with one designed to fire coal. This section presents a description of the various types of coal-fired boilers which are available and examines factors which impact the replacement of a gas/oil-fired boiler with a coal-fired unit. In addition, the costs of boiler replacement are presented, and changes in emissions which result when a gas/oil-fired unit is replaced by a new coal boiler are estimated.

4.3.1.1 Boiler Replacement - Process Description--

There are several factors which must be considered by an industrial boiler operator who is considering replacement of an existing gas/oil boiler with a coal-fired unit. These factors are:

1) Coal Availability
2) Auxiliary Equipment
3) Type of Boiler
4) Costs
5) Pollution Control

The following discussion examines the first three of these factors in more detail. Costs are addressed in Section 4.3.1.2 and Pollution Control is discussed in Section 4.3.1.3.

Coal availability--The first consideration in determining the feasibility of replacing a gas/oil boiler is the availability of coal. An industrial boiler operator must be able to obtain an adequate supply of coal to insure continued production. Generally, the unreliability of a natural gas or oil supply will be one of the reasons for switching to coal. So, before plans for a fuel switch can progress, a supply of coal must be secured.

Several studies have been conducted which predict an adequate supply of coal based on expected growth rates through 1985 (PR-203). However, other studies have indicated that 250 new coal mines would be required by 1985 to meet projected demand for coal (FU-100). Because of these conflicting projections, it appears that coal availability must be determined on a case-by-case basis.

Another factor which must be considered in conjunction with coal availability is the availability of transportation to deliver coal from the mine to the site where it will be used. Generally, coal is delivered by rail or truck, and barge transportation is common in some areas. In nearly all instances, one, two or all three of these delivery systems are available. However, existing transportation systems may not be capable of handling the quantity of coal which will be needed by an individual plant site. This aspect of fuel switching must be examined on an individual basis to determine the transportation requirement.

Auxiliary equipment--Auxiliary equipment required as part of a new coal-fired boiler includes coal handling and storage and ash handling equipment. The primary consideration in selection of this equipment is the plant space required to accommodate it. In many existing plants, space is limited or it may not be available at all. This is especially true if the new boiler is placed in the same location as the one which it is replacing. However, because a completely new unit is being installed, its location is restricted only by land availability.

The actual design of a coal handling system is very site-specific. Whether the system is simple or complex depends on how coal is received, how the plant is situated, and what is expected from the system in terms of capacity, flexibility, etc. There are many kinds of handling equipment available to meet individual plant requirements. A general list of these is presented in Table 4-7. As shown, there are many methods for coal handling and storage and combinations of these can result in a large variety of coal handling systems.

There are three basic types of ash handling systems in use. They are:

1) Vacuum
2) Pneumatic
3) Wet Sluicing.

The vacuum system is commonly used in plants which product 750 metric tons/day or less of ash (approximately 220 MW - 750 x 10^6 Btu/hr). Key elements in this system are: a conveyor pipeline for moving ash and dust from collecting hoppers at the stack and furnace, an airtight receiver for separating ash and air, an automatic discharge gate for channeling ash to a storage bin, an air washer to collect ash and dust particles before discharge of the air, and a steam, hydraulic, or mechanical exhauster.

For plants which produce between 750 and 2500 metric tons/day of ash, pneumatic ash handling systems are employed. These systems are similar to a vacuum system. However, positive pressure rather than a vacuum provides the driving force to convey the ash. Because pressure in a pneumatic system is not limited (in a vacuum system the highest driving force is limited to the difference between the vacuum and atmospheric pressure), larger quantities of ash can be conveyed for longer distances.

TABLE 4-7. AVAILABLE COAL HANDLING AND STORAGE EQUIPMENT[1]

Unloading	Storage	Handling
Rail Car and Barge Movers	Bulldozers	Skip Hoists
Rail Car Thawing Equipment	Scrapers and Carryalls	Bucket Elevators
Rail Car Shakers/Unloaders	Bridges and Tramways	Belt Conveyors
Rotary-Car Dumpers	Cranes and Buckets	Flight Conveyors
Cranes and Buckets	Conveyor Systems	Screw Conveyors
Self-Unloading Boats	Bins and Bunkers	Stacking Conveyors
Unloading Towers	Silos	Chutes
Portable Conveyors	Indicators	Lift Trucks
Lift Trucks with Scoops	Alarms	Monorails and Tramways
Track Hoppers	Vibrators	
Feeders	Gates and Valves	
Weighing Equipment		

[1] Source: PO-097

Wet sluicing systems are employed in plants which produce over 2500 metric tons/day of ash. In general, these systems are only found in very large power plants which require long-distance conveying of ash.

Boiler type--There are two basic types of coal-fired boilers: stoker-fired and pulverized coal-fired. The type of boiler which is used to replace an existing gas- or oil-fired unit will vary, depending on several factors, the most important of which is size. In general, a stoker-fired boiler will be used to replace units smaller than 75 MW (250 x 10^6 Btu/hr) and a pulverized coal boiler will replace units larger than this. However, there are some exceptions. Stokers have been constructed with capacities up to 150 MW (500 x 10^6 Btu/hr) and some pulverized coal (p-c) boilers have capacities as low as 25 MW (90 x 10^6 Btu/hr).

Stoker-fired boilers - In stoker-firing, coal is pushed, dropped, or thrown onto a grate by a mechanical device called a stoker. Part of the coal is vaporized to form a combustible gas which burns in the furnace above the grate. The remaining coal is burned in the presence of air which flows up through the grate. Ash, which remains after the combustion process is complete, is usually removed from the furnace on a continuous basis by movement of the grate.

Stoker-fired boilers can be divided into two general classes, depending on the direction from which raw coal reaches the grate. These are overfeed and underfeed stokers. The stokers classed as overfeed include the spreader stoker and the mass-burning or crossfeed stoker. The class of underfeed stokers includes single- and multiple-retort units.

Overfeed stokers can be further classified by the type of grate mechanism they employ. Spreader stokers have stationary, dumping, agitating, vibrating, oscillating, and reciprocating grate mechanisms while the mass burning stokers have chain-grate and travelling-grate mechanisms.

Spreader stoker - Spreader stokers are common in industry today. In fact, they represent the majority of new stoker-fired boilers. One reason for this is that they are capable of burning a wide range of coals from high-rank eastern bituminous to lignite. In addition, these units are capable of firing many by-product waste fuels.

Spreader stokers are specified in boilers with capacities between 1.5 MW (5×10^6 Btu/hr) and 150 MW (500×10^6 Btu/hr). Stationary grate units are used for units at the low end of this range and moving grates at the high end. In a spreader stoker, raw, sized coal is thrown into suspension in the furnace by paddles, wheels, or air or steam jets. Fine coal particles in the incoming stream of coal tend to burn in suspension during their travel across the furnace. The larger pieces of coal fall to the grate and form a fuel bed. Volatile components of this coal then vaporize and are burned in the furnace while the remaining coal burns with air which is supplied from below the grate.

Approximately 20 to 25 percent of the coal fed to a spreader stoker burns in suspension above the grate. As a result, the spreader stoker has a very fast response to load swings and the load range extends from 20 percent to maximum capacity. Unfortunately, the combustion of fine particles in suspension also has a drawback. Suspension-burning results in increased particulate carryover in comparison to other stokers, and much of this carryover is unburned combustiles. As a result, a fly ash reinjection system is required.

Mass-burning stoker - Mass-burning stokers are either chain- or travelling-grate, and they range in size from 2 MW (7.5×10^6 Btu/hr) to 75 MW (250×10^6 Btu/hr). The chain-grate stoker design was developed for bituminous coal and the travelling-grate design for smaller sizes of anthracite.

In a mass-burning stoker, the grate resembles a wide conveyor belt. This grate moves slowly from one end of the furnace (the feed end) to the other. At the feed end, coal sized below 3.2 cm (1.25 inches) is supplied to the grate from a hopper. As the coal moves toward the opposite end of the furnace, it is ignited, vaporization of volatile compounds occurs, and coke is formed. This coke is burned and the fuel-bed gets progressively thinner.

By the time the coal reaches the far end of the furnace, nothing remains but ash which falls off the grate into an ash pit.

As a class, mass-burning stokers are well suited for a variety of solid fuels. Peat, lignite, subbituminous, free-burning bituminous, or anthracite can be burned. However, strongly caking bituminous coals present a problem. These coals have a tendency to mat and prevent proper passage of air through the fuel bed, causing unburned carbon to be discharged into the ash pit. Strongly caking coals also impact a mass-burning stoker's ability to respond to rapidly changing load.

Single- and multiple-retort stokers - Single-retort stokers range in size from 1.5 MW (5 x 10^6 Btu/hr) to 15 MW (50 x 10^6 Btu/hr) while multiple-retort stokers, although rarely purchased now, have been built in sizes ranging from 15 MW (50 x 10^6 Btu/hr) to 120 MW (400 x 10^6 Btu/hr) (PO-098).

Single- and multiple-retorts are underfeed stokers. As the name implies, raw coal is fed onto the grate from below. Coal, sized below 3.2 cm (1.25 inches), is pushed from a trough or retort located in the center of the grate onto the grate. This coal, which is dried somewhat in the retort, ignites once on the grate. Volatile material is vaporized and is burned in the furnace. The coke formed is burned as it travels across the grate into an ash pit (BE-530).

Underfeed stokers, especially the multiple-retort type, were used extensively some years ago. This was primarily due to the ability of the retort system to burn highly caking coals. However, the high initial capital cost and high maintenance costs associated with these units have made them less competitive in the present industrial boiler market (FU-100).

Pulverized coal-fired boilers - Pulverized coal (p-c) boilers only become economical in sizes above 75 MW (250 x 10^6 Btu/hr) even though they are 3 to 5 percent more efficient than stoker-fired boilers. The reason for this is that the capital and operating costs associated with coal pulverizers are higher than the costs of stoker firing. Only in larger units do fuel savings outweigh the increased costs of p-c firing (PO-098).

In a p-c boiler, raw coal is dried and pulverized in a coal mill to produce a fine, dry, powdered coal. Typical coal product from the mill is 70 percent less than 0.74 µm (200 mesh) with less than 2 percent larger than 297 µm (48 mesh). This pulverized coal is then conveyed pneumatically to the boiler. The air which dries and conveys the coal is primary combustion air which has passed through the preheater.

Once the pulverized coal reaches the boiler it is injected into the furnace where volatile components are vaporized. Enough air is introduced with the coal to burn these volatiles. The char which remains is heated by combustion of the volatiles and it burns in suspension in the furnace. Secondary air, which is introduced around the burner, supplies oxygen for combustion of the char.

Although p-c units are a single class of boilers, there are variations in the type of pulverizer and the type of burners which are used. Table 4-8 presents a list of the various pulverizers and burners. The specific equipment which is used at a particular plant will depend on coal characteristics and the size of the boiler.

TABLE 4-8. TYPES OF PULVERIZED-COAL EQUIPMENT[1]

Burners	Pulverizers
Horizontal Burner	Ball Mill
Circular Register Burner	Tube Mill
Intervane Burner	Roll-and-Race Pulverizer
Directional Burner	Ball-and-Race Pulverizer
	Bowl Mill
	Attrition Mill

[1] Source: PO-098

The major advantage of a p-c boiler is the improved thermal efficiency of this type of unit. Principal disadvantages are increased capital and operating costs and increased particulate emissions over those associated with a stoker-fired boiler. The increased costs are associated with the initial price and high operating costs of the coal mills. The increased particulate emissions result because suspension burning of the coal promotes carryover of fly ash from the furnace. In stoker-firing, most of this ash remains on the grate and is collected in the ash pit.

4.3.1.2 Costs of Boiler Replacement--

The costs of replacing an existing gas/oil-fired boiler have not been estimated. However, costs of new coal-fired boilers are available.

The costs of a new boiler may be higher than the costs of replacing an existing boiler. If existing fans, steam lines, feedwater treatment, etc. can be used, costs of replacement may be approximately 15 percent less than the cost of a new boiler (IC-005). But, if the new boiler must be installed with all new facilities, savings will not be significant.

Capital costs--The capital costs for a new boiler include the direct costs of land, permits, yardwork, fuel handling, storage, boiler house, boiler equipment, ash handling, and utilities. In addition, indirect costs associated with construction, engineering, contingency, and working capital are included.

Figure 4-6 presents a comparison of the capital costs of stoker-, pulverized coal-, and gas/oil-fired boilers. As illustrated, the costs of these boilers increase exponentially as a function of boiler size. The value of the exponent is approximately 0.8. The cost data presented in Figure 4-6 are based on manufacturers prices. The Chemical Engineering plant cost index was used to escalate costs to mid-1978.

The boiler costs presented in Figure 4-6 show that a p-c boiler costs between 1.2 and 1.25 that of a stoker-fired unit. The economic breakpoint

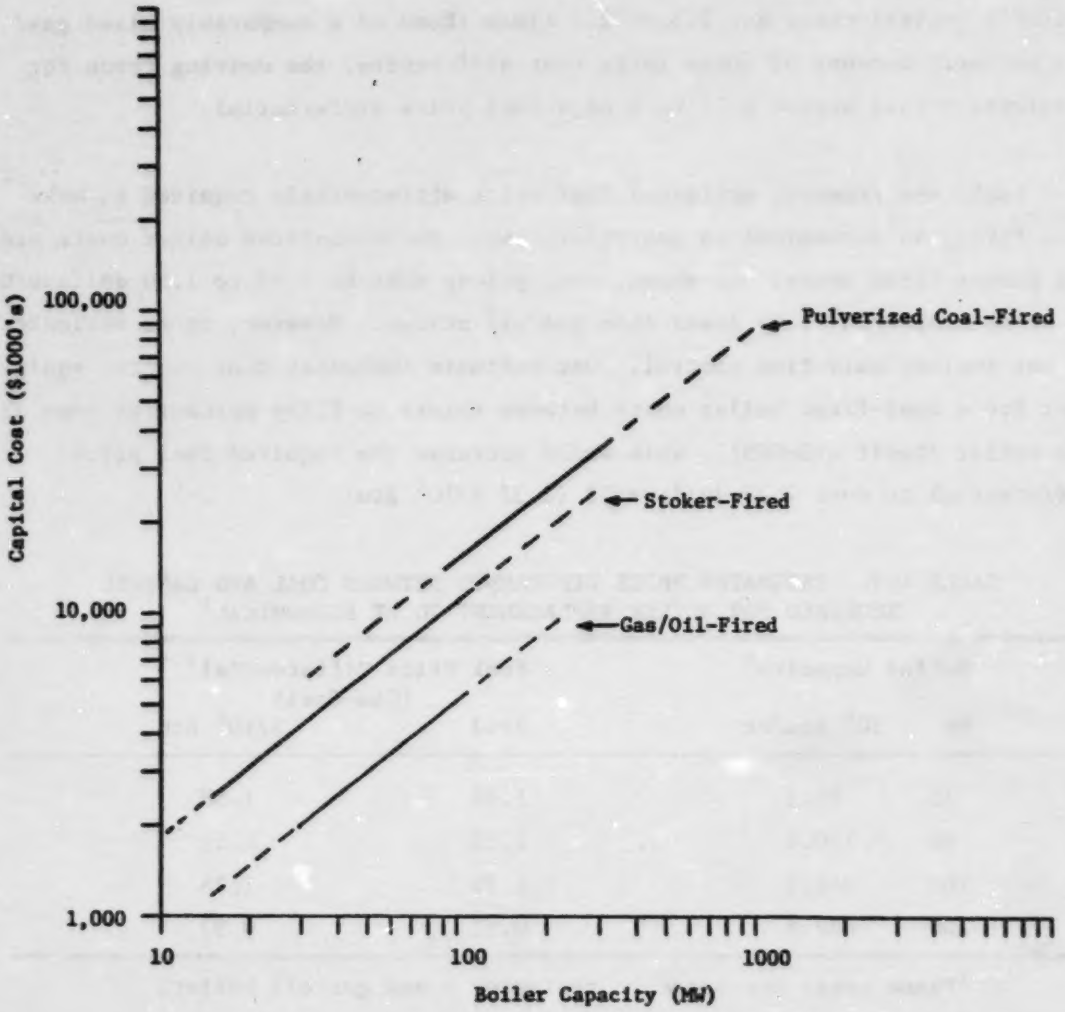


Figure 4-6. A comparison of stoker-, pulverized coal- and gas/oil-fired boiler capital costs (1978$).[1]

[1] Source: EN-761, CO-735

between stoker firing and p-c firing occurs around 75 MW (250×10^6 Btu/hr). The exact size where this occurs depends primarily on the cost of coal.

A comparison of stoker costs to gas/oil fired costs indicates that a stoker requires 2.0 to 2.25 times more capital to install, while a p-c boiler's capital costs are 2.5 to 2.7 times those of a comparably sized gas/oil boiler. Because of these large cost differences, the driving force for a voluntary fuel switch will be a high fuel price differential.

Table 4-9 presents estimated fuel price differentials required to make coal-firing as economical as gas/oil-firing. The coal-fired boiler costs are for stoker-fired units. As shown, coal prices must be 0.92 to 1.50 dollars/GJ (0.97 to 1.58 $\$/10^6$ Btu) lower than gas/oil prices. However, these estimates do not include pollution control. One estimate indicates that control equipment for a coal-fired boiler costs between thirty to fifty percent as much as the boiler itself (IC-005). This would increase the required fuel price differential to over 2.25 dollars/GJ (2.37 $\$/10^6$ Btu).

TABLE 4-9. ESTIMATED PRICE DIFFERENCE BETWEEN COAL AND GAS/OIL REQUIRED FOR BOILER REPLACEMENT TO BE ECONOMICAL[1]

Boiler Capacity[2]		Fuel Price Differential[3,4] (Gas-Coal)	
MW	10^6 Btu/hr	$/GJ	$\$/10^6$ Btu
25	85.3	1.50	1.58
50	170.6	1.28	1.36
100	341.3	1.21	1.28
200	682.6	0.92	0.97

[1] These costs are based on replacing a new gas/oil boiler.

[2] Costs are estimated at 4000 hrs/year operation at 100 percent of capacity.

[3] This price differential is based on a 20 percent annual return on capital.

[4] No pollution control equipment is included in this estimate.

Figures 4-7 and 4-8 present projected capital costs for stoker and p-c boilers respectively. Costs are projected for 1985, 1990, and 1995 based on a linear extrapolation of historical boiler cost data supplied by Babcock and Wilcox (SM-201).

Operating and maintenance costs--The operating and maintenance (O&M) costs for a coal-fired boiler are presented in Figure 4-9. As illustrated, these costs are relatively insensitive to boiler size below 30 MW (100 x 10^6 Btu/hr). However, above 30 MW, these costs increase rapidly (EN-761).

Table 4-10 presents O&M costs as a percentage of annualized costs. As illustrated, these costs represent between 7 and 16 percent of the annualized costs.

TABLE 4-10. OPERATING AND MAINTENANCE COSTS FOR A COAL-FIRED BOILER AS A PERCENTAGE OF ANNUAL COSTS[1]

Boiler Capacity[2]		Operating and Maintenance Costs[3] (% of Annualized Costs)		
MW	10^6 Btu/hr	High Sulfur Coal	Low Sulfur Coal (eastern)	Low Sulfur Coal (western)
25	85.3	15.6	13.7	12.2
50	170.6	14.8	12.9	11.4
100	341.3	12.2	10.5	9.1
200	682.6	9.9	8.4	7.3

[1] Annual costs are estimated at a 20 percent annual return on capital.

[2] Costs are estimated at 4000 hrs/year operation at 100 percent of capacity.

[3] 1978 costs for coal are: High Sulfur Coal - 0.70 \$/GJ (0.74 \$/10^6 Btu)
Low Sulfur Coal (eastern) - 1.13 \$/GJ (1.19 \$/10^6 Btu)
Low Sulfur Coal (western) - 1.58 \$/GJ (1.67 \$/10^6 Btu)

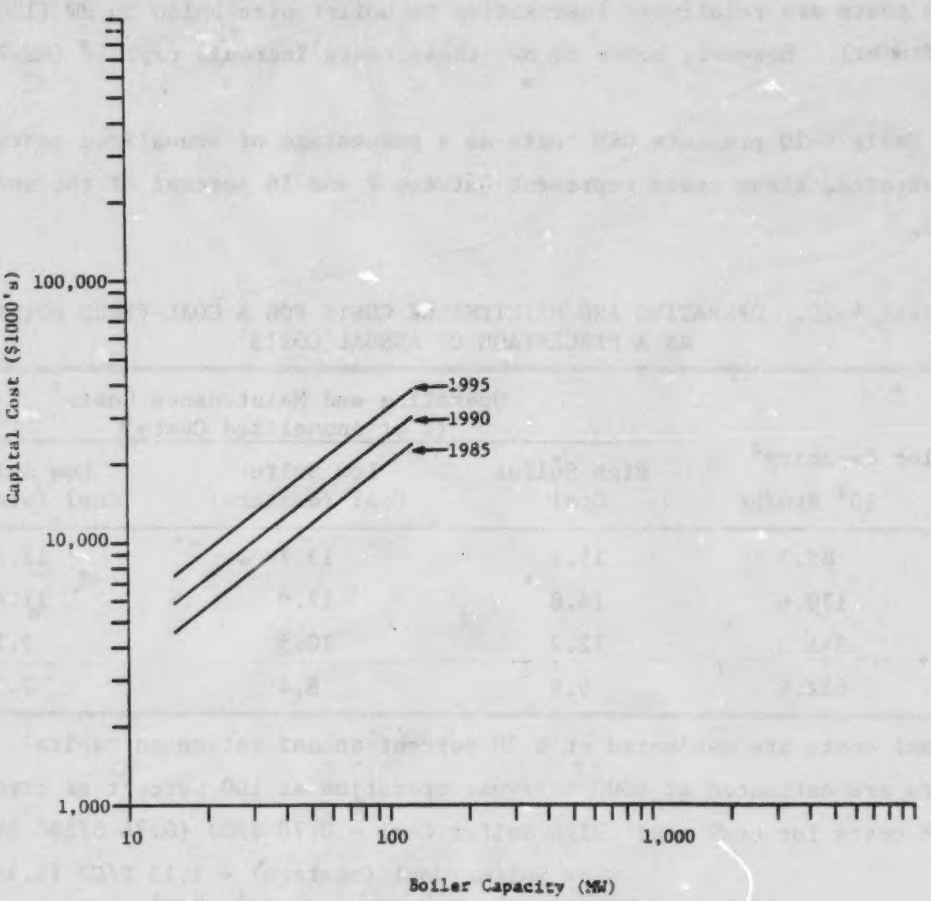


Figure 4-7. Projected capital costs for a stoker-fired boiler.
Source: EN-761, CO-735, SM-201

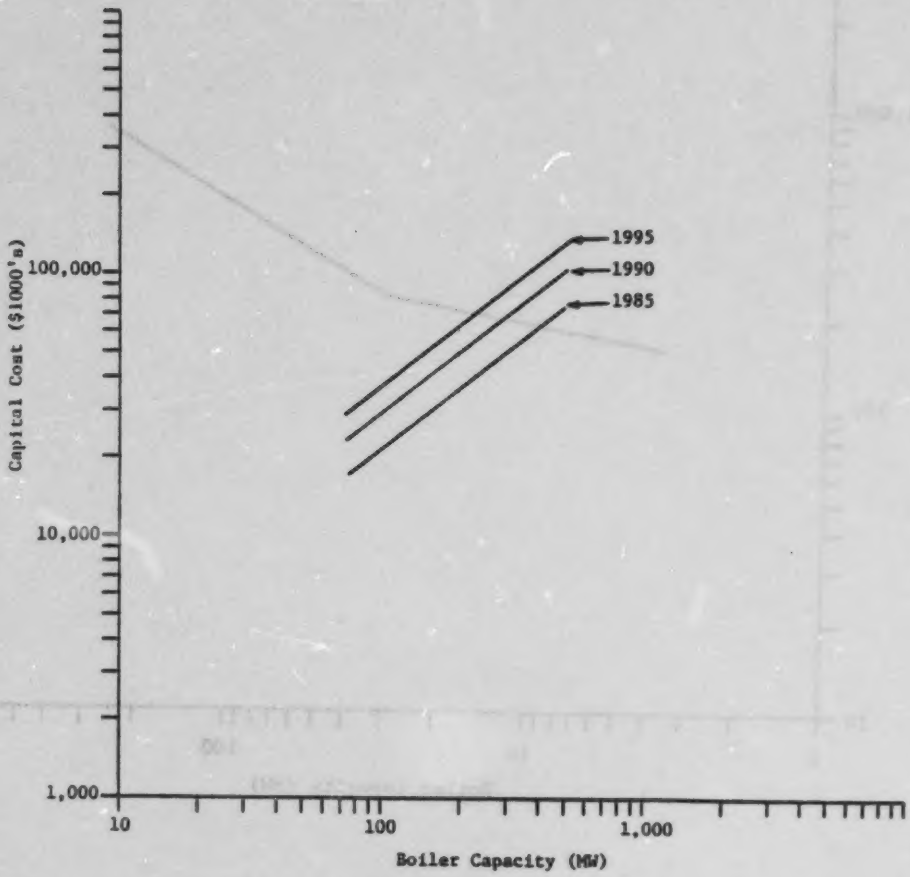


Figure 4-8. Projected capital costs for a pulverized coal-fired boiler.
Source: EN-761, CO-735, SM-201

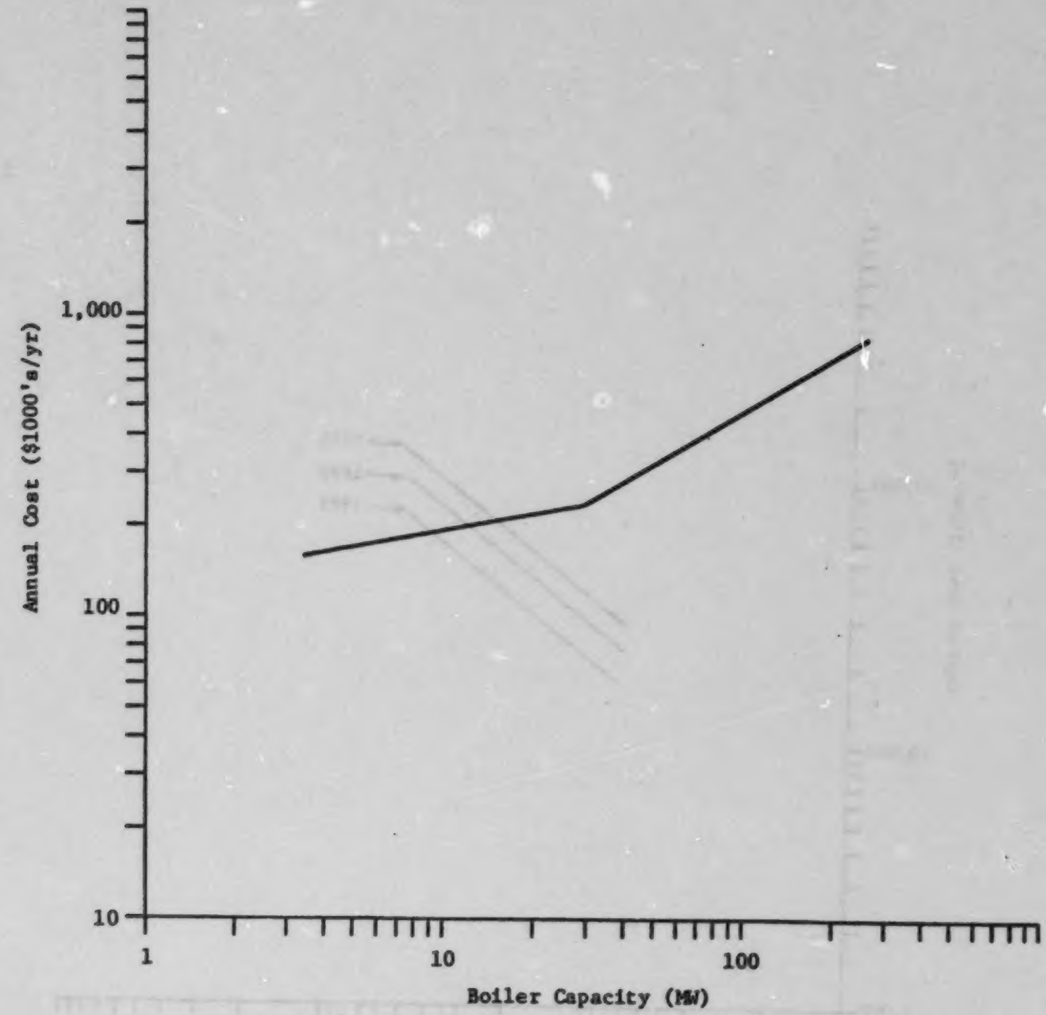


Figure 4-9. Estimated operating and maintenance costs for a coal-fired boiler.

Load Factor: (4000 hrs/yr at 100 percent capacity)

Source: EN-761

Figure 4-10 compares coal-fired boiler O&M costs with those of natural gas/oil. As illustrated, coal-fired costs are approximately four to five times greater. The main reason for this cost increase is the difference in labor requirements for boilers firing these fuels.

4.3.1.3 Environmental Impact--

Replacement of an existing gas/oil-fired boiler with a coal-fired unit will result in an increase in uncontrolled emissions. However, pollution control systems are available to reduce these emissions. The following discussion examines emissions from a coal-fired boiler. Emission estimates for particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, and hydrocarbons are included. In addition, applicable emission control techniques are identified.

Estimated emissions--Table 4-11 compares the estimated emissions from four different coal-fired boilers to typical state regulations. These estimates are for uncontrolled emissions and are based on emission factors developed by PEDCo Environmental Specialists (PE-348).

As shown in Table 4-11, all of the 12 cases have higher emission rates of particulates than those allowed by the typical state regulations, 4 of the 12 have emission rates of sulfur dioxide which are above typical state limits, and none of the emission rates for nitrogen oxides are higher than the typical state regulations. The comparison in Table 4-11 indicates that sulfur oxide and particulate pollution controls may be required by smaller units.

Pollution control equipment--A detailed examination of pollution control techniques which are applicable to industrial boilers is being conducted as part of the study to develop background information to support industrial boiler NSPS. The following discussion briefly examines the applicability of available pollution control technology to a new, coal-fired industrial boiler.

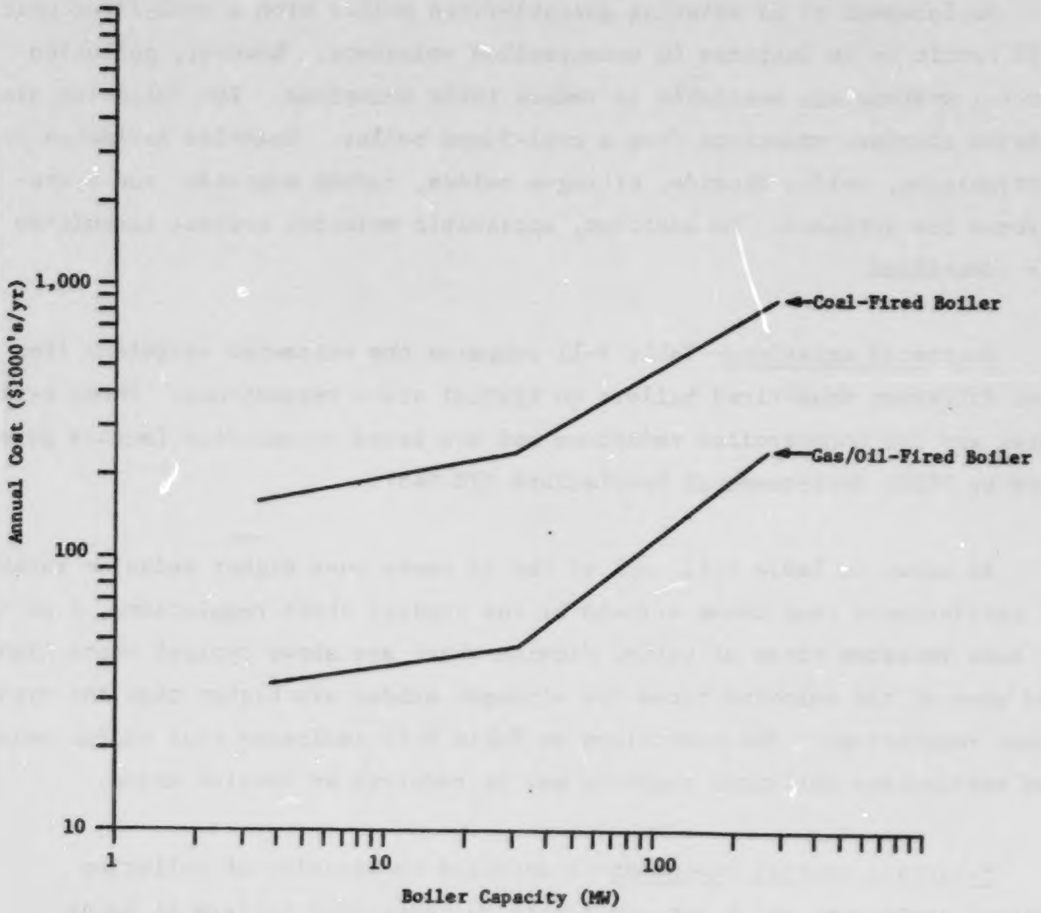


Figure 4-10. Comparison of operating and maintenance costs of a gas/oil-fired boiler and a coal-fired boiler.

Load Factor: (4000 hrs/yr at 100 percent capacity)

Source: EN-761

TABLE 4-11. A COMPARISON OF ESTIMATED INDUSTRIAL COAL-FIRED BOILER EMISSIONS TO TYPICAL STATE REGULATIONS[1]

Boiler Type	Pollutant	High Sulfur Coal[2] ng/J	High Sulfur Coal[2] lb/10^6 Btu	Low Sulfur Eastern Coal[2] ng/J	Low Sulfur Eastern Coal[2] lb/10^6 Btu	Low Sulfur Western Coal[2] ng/J	Low Sulfur Western Coal[2] lb/10^6 Btu	Typical State Regulations ng/J	Typical State Regulations lb/10^6 Btu
Underfeed Stoker									
	particulates	945.8	2.2	537.4	1.25	601.9	1.4	257.9	0.6
	sulfur dioxide	1805.7	4.2	387.0	0.9	387.0	0.9	1075.0	2.5
	nitrogen oxides as NO$_2$	154.8	0.36	154.8	0.36	154.8	0.36	301.0	0.7
	carbon monoxide	36.5	$8.5\text{x}10^{-2}$	31.0	$7.2\text{x}10^{-2}$	44.7	$10.4\text{x}10^{-2}$	-	-
	hydrocarbons as CH$_4$	18.1	$4.2\text{x}10^{-2}$	15.5	$3.6\text{x}10^{-2}$	22.4	$5.2\text{x}10^{-2}$	-	-
Chaingrate Stoker									
	particulates	859.9	2.0	473.0	1.1	533.1	1.24	257.9	0.6
	sulfur dioxide	2450.8	5.7	537.4	1.25	515.9	1.2	1075.0	2.5
	nitrogen oxides as NO$_2$	107.5	0.25	107.5	0.25	107.5	0.25	301.0	0.7
	carbon monoxide	36.5	$8.5\text{x}10^{-2}$	31.0	$7.2\text{x}10^{-2}$	44.7	$10.4\text{x}10^{-2}$	-	-
	hydrocarbons as CH$_4$	18.1	$4.2\text{x}10^{-2}$	15.5	$3.6\text{x}10^{-2}$	22.4	$5.2\text{x}10^{-2}$	-	-
Spreader Stoker									
	particulates	1074.9	2.5	601.9	1.4	687.9	1.6	257.9	0.6
	sulfur dioxide	3611.6	5.9	558.9	1.3	537.4	1.25	1075.0	1.2
	nitrogen oxides as NO$_2$	249.4	0.58	249.4	0.58	249.4	0.58	301.0	0.7
	carbon monoxide	36.5	$8.5\text{x}10^{-2}$	31.0	$7.2\text{x}10^{-2}$	44.7	$10.4\text{x}10^{-2}$	-	-
	hydrocarbons as CH$_4$	18.1	$4.2\text{x}10^{-2}$	15.5	$3.6\text{x}10^{-2}$	22.4	$5.2\text{x}10^{-2}$	-	-
Pulverized Coal									
	particulates	2751.7	6.4	1547.8	3.6	1719.8	4.0	257.9	0.1
	sulfur dioxide	1719.8	4.0	387.0	0.9	365.5	0.85	1075.0	1.2
	nitrogen oxides as NO$_2$	254.5	0.59	254.5	0.59	254.5	0.59	301.0	0.7
	carbon monoxide	18.1	$4.2\text{x}10^{-2}$	15.5	$3.6\text{x}10^{-2}$	22.4	$5.2\text{x}10^{-2}$	-	-
	hydrocarbons as CH$_4$	5.6	$1.3\text{x}10^{-2}$	4.7	$1.1\text{x}10^{-2}$	6.9	$1.6\text{x}10^{-2}$	-	-

[1] Source (PE-348)

[2] Fuel analyses are:

	High Sulfur Coal	Low Sulfur Eastern Coal	Low Sulfur Western Coal
Sulfur	3.5 percent	0.9 percent	0.6 percent
Ash	10.6 percent	6.9 percent	5.4 percent
HHV	27,500 (kJ/kg)	32,150 (kJ/kg)	22,370 (kJ/kg)

Particulate control - There are four types of pollution control equipment which can be used to reduce particulate emissions in flue gas from an industrial boiler. They are:

1) Mechanical Collectors
2) Fabric Filters
3) Electrostatic Precipitators
4) Wet Scrubbers.

Mechanical collectors - Mechanical collectors are efficient devices for removing relatively large particles from flue gas. They can be designed to remove 98 percent of the particles above 5 μm (6.0×10^{-6} ft) at an intermediate pressure drop (0.75 to 1.0 kPa - 3 to 4 inches H_2O). These collection devices are more applicable to emissions from stoker-fired units than p-c units. This is because over 90 weight percent of the particulate emissions from a stoker-fired boiler are larger than 5×10^{-6}m. This compares with approximately 80 weight percent larger than 5×10^{-6}m for p-c boilers (HU-234).

Mechanical collectors may be required on a stoker-fired industrial boiler to collect fly ash particles which contain unburned carbon. These particles can be reinjected into the boiler to improve thermal efficiency. However, it is unlikely that mechanical collectors will be used on industrial boilers to meet emission regulations. In general, these devices are not efficient enough to economically reduce emissions to required levels.

Fabric filters - Fabric filters are capable of removing over 99.5 percent of incoming particulates from coal-fired flue gas and the collection efficiency depends only on the physical properties of the fly ash. But these filters operate at a intermediate pressure drop (1.0 to 1.5 kPa - 4 to 6 inches H_2O) with consequent high operating costs.

One study conducted by Enviro-Systems and Research, Incorporated indicated that, although fabric filters have a higher operating cost than electrostatic precipitators, the lower capital costs of the filters make them economically competitive on an annualized cost basis. This study was for a low sulfur coal and the results may not apply to the high sulfur case. However, it does appear that fabric filters are applicable for controlling emissions from coal-fired industrial boilers (MC-120).

Electrostatic precipitators - Electrostatic precipitators (ESP) have been installed on many coal-fired boilers in the past. ESP's are capable of removing 99.9 percent of particulates from an industrial boiler flue gas and the pressure drop across an ESP is very low (0.25 to 0.5 kPa - 0.5 to 1.5 inches H_2O).

Unlike a fabric filter, the collection efficiency of an ESP depends on the chemical properties of the fly ash. As a result, ESP's may not be suitable for application on all coal-fired boiler flue gases. This is particularly true of flue gas from the combustion of western coals.

Wet scrubbers - Wet scrubbers are capable of removing over 99 percent of the fly ash in the flue gas from a coal-fired boiler, but only at very high pressure drops (5.0 to 7.5 kPa - 20 to 30 inches of water) with resultant high operating costs. In addition, the water handling systems associated with wet scrubbing add to the operating costs.

In general, wet scrubbers are not economical for particulate control. However, if sulfur dioxide (SO_2) is a problem, wet scrubbers can be used to control emissions of both particulates and SO_2.

Sulfur dioxide emissions - There are three methods which can be used to limit SO_2 emissions from a new, coal-fired industrial boiler. They are:

1) Use of Low Sulfur Coal Fuel
2) Physical and Chemical Coal Desulfurization
3) Flue Gas Desulfurization (FGD)

The first two of these methods limit SO_2 emissions by reducing the quantity of sulfur in the fuel to the boiler while FGD removes SO_2 from the flue gas leaving the boiler.

The use of low sulfur coal is the simplest method to limit SO_2 emissions. However, the supply of low sulfur coal is limited. One study estimates that only 9 percent of the United States coal reserves are low enough in sulfur to meet current utility boiler NSPS (PE-289). As a result, low sulfur coal will only be used on a limited basis in new coal-fired industrial boilers.

Physical and chemical coal cleaning are processes which treat a high sulfur coal to produce a low sulfur coal product. Physical coal cleaning can be adapted to remove up to 80 percent of coal pyrites (comprising 20 to 80 percent of total sulfur content depending upon the characteristics of the coal) but, to accomplish this, more refined processing methods are necessary. As a result, physical coal cleaning will have only a limited role in reducing SO_2 emissions from coal-fired industrial boilers (ST-562).

Chemical coal cleaning has the potential for removing 95 percent of the pyritic sulfur and 40 percent of the organic sulfur from coal. EPA is currently conducting tests on a prototype unit using an aqueous ferric sulfate leaching process and is also evaluating seven or eight other processes for future study. Commercialization of chemical coal cleaning processes is not expected before the mid 1980's (ST-562).

Flue gas desulfurization appears to be the technology which will be widely applied to limit SO emissions from new, coal-fired industrial boilers. FGD systems are capable of achieving over 90 percent reduction in SO emissions from coal-fired boiler flue gases. However, FGD systems are generally complex and they have the potential to reduce the reliability of the boiler system. This could present a problem to many industrial users. In addition, FGD systems produce a by-product or waste stream which contains the sulfur that was removed from the flue gas. Disposal of this by-product or waste will also limit FGD system applicability. Other considerations for an FGD system include space requirements, and the high costs associated with these systems.

Nitrogen oxide emissions - Nitrogen oxide emissions from industrial boilers can be limited by combustion modifications and by flue gas treatment (FGT). If new, coal-fired industrial boilers are required to reduce NO_x emission levels, it is likely that their design will incorporate combustion modifications. This will reduce potential NO_x emissions between 30 and 50 percent.

Flue gas treating can reduce NO_x emissions by up to 90 percent. However, this technology has not been demonstrated in the United States and it will be expensive. As a result, FGT will not be used to reduce NO_x emissions unless combustion modifications cannot meet regulations.

4.3.2 Boiler Modification - Gas/Oil to Coal

Modification of an existing gas- or oil-fired boiler to permit direct combustion of coal is technically possible. However, in nearly all instances, the extent of the modifications required makes direct combustion of coal practically impossible. Exceptions to this statement are gas- and oil-fired boilers which were originally designed to fire coal. Some of these boilers may have the potential to convert to coal.

The following discussion examines the modifications which are required to convert a gas/oil-fired boiler to coal. Two cases are presented. The first describes the conversion of a boiler which was not designed to burn coal. The second describes the conversion of a gas/oil-fired boiler which was originally designed to fire coal.

4.3.2.1 Process Description - Boiler Modification - Gas/Oil to Coal--

Conversion of a boiler not designed to fire coal--The design of a boiler is based on the type of fuel which will be burned. The fuel handling equipment, combustion equipment, heat transfer surfaces, fans, pollution control equipment, etc. all depend on the fuel. Consequently, a change in fuels in an existing boiler will necissitate a change in almost every facet of the boiler design. This is especially true for a switch in fuels from gas/oil to coal.

The most obvious and unavoidable impact of switching an existing gas/oil-fired boiler to coal will be derating of the boiler. If no provision was made for coal-firing during the design of a boiler, the boiler cannot be converted to coal-firing without reducing capacity by at least 50 percent. The two major reasons why this derating occurs are furnace size and flue gas velocity.

Furnace size is important because for a given capacity, a coal-fired boiler furnace is approximately twice as large as the furnace in a gas/oil-fired boiler. Therefore, only about one-half as much coal (based on heat input) can be fired in an existing gas/oil-fired unit. This reduction in firing rate is necessary to reduce the furnace heat release rate in order to prevent hot spots in the furnace, slag formation on furnace walls, and plugging of gas passages in the convective section of the boiler.

Flue gas velocity is important because the ash in coal requires that flue gas velocity in a coal-fired unit be less than in a gas/oil-fired unit to prevent erosion of tubes in the convective section of the boiler. This design constraint would reduce boiler capacity by 30 percent in a switch from gas/oil to coal if flue gas quantities were the same for gas/oil and coal, but for a given heat input, a coal-fired boiler produces 20 to 40 percent more flue gas. As a result, boiler capacity must be reduced between 40 to 60 percent based on flue gas velocity considerations (FR-198).

In addition to derating a boiler, major modifications are required before coal can be successfully fired in an existing gas/oil boiler. These modifications are:

1) Addition of coal handling and storage equipment,
2) Addition of coal firing equipment,
3) Addition of ash handling equipment,
4) Modification of the convective section of the boiler,
5) Modification of structural steel, ductwork, and fans, and
6) Addition/modification of pollution control equipment.

The following discussion examines each of these modifications in more detail. This discussion is based on the assumption that an adequate supply of coal is available and that facilities exist for receiving coal at the plant site.

Coal handling and storage - The first requirements for converting to coal are the facilities and equipment needed for storage and handling of solid fuel. Storage consists of both active and stockpile storage. The active storage feeds directly to the boiler. Good design practices usually require a 5 to 10 day supply of coal in active storage. This should prevent interruptions in the boiler feed due to failure of in-plant coal handling equipment.

Stockpile storage is a 30 to 90 day supply of coal. This supply is usually maintained as a coal pile, stored in the open. However, dust problems or other considerations may require that the stockpile be enclosed. A stockpile is maintained to prevent interruptions in the coal supply due to mining or transportation strikes, etc.

Coal handling equipment is required to move coal from the unloading area to the stockpile and from the stockpile to the active storage. Coal handling systems can consist of front-end loaders, bucket elevators, conveyor belts, etc.

The space required for coal storage and handling is usually extensive. In most cases, storage and handling will require several times the area required by the boiler. And in many instances, this space is not available.

Coal firing equipment - Extensive modification of existing gas- and oil-fired boilers is required to install coal firing equipment. This is especially true in the case of a conversion to stoker-firing. If stoker-firing is used, the furnace will need to be rebuilt. At a minimum, it will be necessary to remove the existing boiler front to accommodate the coal-feed system, to mount a mechanical grate and drive system on the boiler floor, and to install an air supply system under the grate, an overfire air system above the grate, and an ash pit. This may necessitate raising the boiler 20 to 30 feet above the ground.

If an existing gas/oil-fired boiler is converted to pulverized coal firing, coal mills must be installed to crush the coal feed. Ductwork must be modified to reroute preheated combustion air through the coal mills. This air is needed to dry the pulverized coal and to convey it to the boiler. Other modifications include installation of pulverized coal burners, and modification of the furnace floor to accommodate a bottom ash removal system.

Ash handling equipment - Existing gas and distillate oil boilers are not designed to handle the ash which is in coal. And residual oil boilers are designed to handle only a fraction of this ash. Therefore, conversion of a gas/oil boiler to coal will require either installation or modification of ash handling and disposal equipment.

An ash handling system consists of conveying, storage, and disposal. Most industrial operations use a vacuum system to convey ash. This system uses the difference between atmospheric pressure and a vacuum to convey ash from the boiler to an ash hopper. After ash has been collected in hoppers, it is removed for disposal, usually in trucks.

Ash disposal is a major problem in many existing industrial plants. Environmental and space considerations may require long-distance hauling of ash. This can significantly impact the costs of disposal.

Convective section modifications - The convective section of a boiler designed for gas/oil firing is markedly different from that of a boiler designed for coal firing due primarily to the variation in ash content between gas/oil and coal. The wide tube spacing in a coal-fired unit is designed to prevent plugging of gas passages. For example, in a gas/oil-fired unit, superheater tubes are spaced at 2.5 cm (1 inch) centers while in a coal-fired unit the tubes must be spaced on 20 to 41 cm (8 to 16 inch) centers.

In order to fire coal in an existing unit, the tube spacing must be modified. Modification will usually consist of removal of some of the tubes from the superheater and boiler. In addition, soot blowers must be installed to periodically remove any deposits of ash from the tubes.

Another modification which will be required is a change in the economizer tubes. Most gas/oil-fired boilers have economizers with finned-tubes. The fins provide extended surface area for heat transfer and permit the economizer to be relatively compact. But the ash present in coal flue gas will require a bare-tube economizer. This change is necessary to prevent ash deposits from plugging gas passages and reducing heat transfer in the economizer. Unfortunately, replacing or modifying the economizer will result in a larger economizer because more bare tubes are required to maintain the equivalent heat transfer surface area.

Replacement or modification of the economizer will necessitate changes in the ductwork and the boiler outlet. In addition, the air preheater may require modifications to prevent acid corrosion.

Structural modification - Major structural modifications may be required to convert an existing gas/oil-fired unit to coal firing. Gas and oil boilers usually have solid floors and are bottom-supported. But coal-fired boilers require ash removal system. Thus, they are top-supported. Conversion of a bottom-supported boiler to coal firing will require the construction of new foundations, supporting steel, platforms, and ductwork.

Another modification which may be required is the installation of an induced-draft fan. Gas- and oil-fired boilers usually operate with a forced-draft fan and a pressurized furnace. However, coal-fired boilers operate with an induced-draft fan and a balanced pressure furnace. Therefore, it may be necessary to modify ductwork and install a fan downstream of the air preheater.

Pollution control equipment - Natural gas and distillate oil are very clean fuels with respect to ash and sulfur. And they can usually be fired without pollution control equipment. Residual oil has varying quantities of ash and sulfur and residual oil boilers may require some particulate and sulfur dioxide control equipment, but coal is a relatively dirty fuel. Most coals have a very high (between 6 and 20 percent) ash content and coal combustion will require particulate control. In addition, a large fraction of the coal in the United States (over 90 percent) has a sulfur content which will result in SO_2 emission rates above current utility boiler NSPS if combusted without flue gas desulfurization. Therefore, major consideration must be given to the pollution control equipment required in a switch from gas/oil to coal (PE-289).

At a minimum, gas and distillate oil boilers which are converted to coal will require addition of particulate control equipment. In addition, problems may arise with emissions of sulfur dioxide, nitrogen oxides, carbon monoxide. and hydrocarbons. And in many cases the space required and cost of installation of pollution control equipment will prohibit a switch from gas/oil to coal.

Conversion of a boiler originally designed to fire coal--There are some industrial boilers currently burning clean fuels which were originally designed to fire coal. One study estimates that less than 4 percent of the manufacturing facilities burning gas and oil possess the capability to switch to coal (BE-530). Of these boilers, only a limited number can actually be converted back to coal firing. For example, the Federal Energy Administration identified 680 boilers as potential candidates for conversion to coal. Of these, 425 were discarded as being too old or too small (BA-669).

Reconversion of a boiler will depend on many factors such as the age and size of the unit. Other factors will be site specific. The major considerations are:

1) The condition of the original equipment associated with coal firing.
2) The space available at the plant site for coal and ash handling.
3) Pollution control equipment required to handle increased emissions.

The following discussion examines each of these considerations in more detail.

Condition of coal firing equipment - The coal handling and burning equipment for a boiler which has been converted to gas/oil will have deteriorated to some degree. And in many instances, this equipment may have been completely removed from the plant. The degree of difficulty in converting back to coal will depend to a large extent on the condition of this equipment. The conversion procedure can be as simple as lubrication and replacement of a few parts or conversion can be practically impossible.

The difficulty in reconverting a boiler to coal firing will increase as the length of time since coal was last fired increases. In many instances, when oil or gas was substituted for coal, oil storage tanks replaced the coal storage pile and much of the coal and ash handling equipment was removed to keep the plant area clean. The longer the time since conversion, the greater are the chances that this equipment was removed. However, there are exceptions. Some plants retired the coal and ash handling equipment with the expectation that coal firing might become economical again. These plants should find reconverting a relatively simple process (CO-735).

Space available - Coal firing requires considerably more space than gas or oil firing. And in many cases, a converted coal-fired boiler may not have this space available. Installation of oil storage tanks or general plant expansion may have claimed the space originally occupied by coal and ash handling facilities.

For example, a recent reconversion performed by Battelle's Columbus Labs transformed an uncrowded boiler room into one which is now cramped for space. The area of the steam plant approximately doubled and it had to be extended from the boiler house to the parking lot (FU-100).

Pollution control - The most important consideration in reconverting a boiler to coal-firing is the pollution control equipment required to meet state and federal regulations. In many cases, especially in recent conversions from coal to gas or oil, fuels were switched to meet regulations. This probably resulted from an economic analysis which indicated fuel switching was much less expensive than installation of pollution control equipment.

These boilers which were recently converted from gas/oil to coal are probably the best candidates for reconversion from a technical standpoint. But the costs of complying with emission regulations may prevent reconversion.

4.3.2.2 Costs of Boiler Modification - Gas/Oil to Coal--

The costs of converting an existing gas/oil-fired boiler to coal are not well defined. Most experts agree that a fuel switch from gas/oil to coal in a boiler not designed to fire coal will approach the costs of a new coal-fired boiler. This is especially true if the capacity reduction which results from fuel switching must be replaced by the purchase of additional steam generating capacity.

The costs of converting a gas/oil-fired boiler originally designed to fire coal back to coal are very site-specific. The unique nature of each potential reconversion will determine the costs. The costs can range from almost nothing to the costs of converting a gas/oil-fired boiler which was not designed to fire coal.

No published cost data exist which specifically estimate the cost of switching fuels from gas/oil to coal. But the costs of some of the required boiler modifications have been estimated. The following discussion examines these costs and presents published estimates for them.

Capital costs--Six modifications are required to convert an existing gas/oil fired boiler to coal firng. They are:

1) Addition of coal handling and storage equipment,
2) Addition of coal firing equipment,
3) Addition of ash handling equipment,
4) Modification of the convective section of the boiler,
5) Modification of structural steel, ductwork, and fans, and
6) Addition/modification of pollution control equipment.

Of these modifications, capital cost estimates have been published for coal handling, ash handling, and pollution control equipment.

Figure 4-11 presents capital costs of coal handling and storage equipment. Figure 4-12 presents capital costs of ash handling equipment. The costs of pollution control equipment will not be addressed in this report. Individual Technology Assessment Reports (ITAR's) are being prepared which contain detailed cost estimates for various pollution control technologies.

As illustrated in Figure 4-11, coal handling costs vary exponentially as a function of boiler size. The approximate value for the exponent is 0.9. Coal handling costs range from 6,700 to 12,500 dollars per MW of capacity (2,000 to 3,700 dollars per 10^6 Btu/hr). Based on the boiler costs presented in Section 4.3.1.2, coal handling costs are approximately 5 percent of the costs of a new, coal-fired boiler.

Figure 4-12 shows ash handling costs for a coal-fired boiler. As illustrated, these costs are nearly independent of boiler size for boilers smaller than 75 MW (250 x 10^6 Btu/hr). Above this size, ash handling costs vary exponentially with boiler size. The approximate value for the exponent is 0.8. Ash handling costs range from 3,000 to 45,000 dollars per MW of capacity (1,000 to 13,000 dollars per 10^6 Btu/hr). These costs represent between 5 and 12 percent of the costs of a new, coal-fired boiler.

It is uncertain what percentage of the costs of converting an existing gas/oil boiler to coal-firing are associated with coal and ash handling, but some assumptions can be made. Based on the total modifications required, it appears that coal and ash handling costs for a boiler modification have 2 to 3 times more impact on total costs than they do for new boiler costs. Therefore, for conversion of an existing boiler, coal handling costs can be assumed to represent 10 to 15 percent of the total costs and ash handling costs represent from 10 to 36 percent of the total costs. Assuming values of 12 and 20 percent for coal and ash handling costs respectively, the costs of boiler

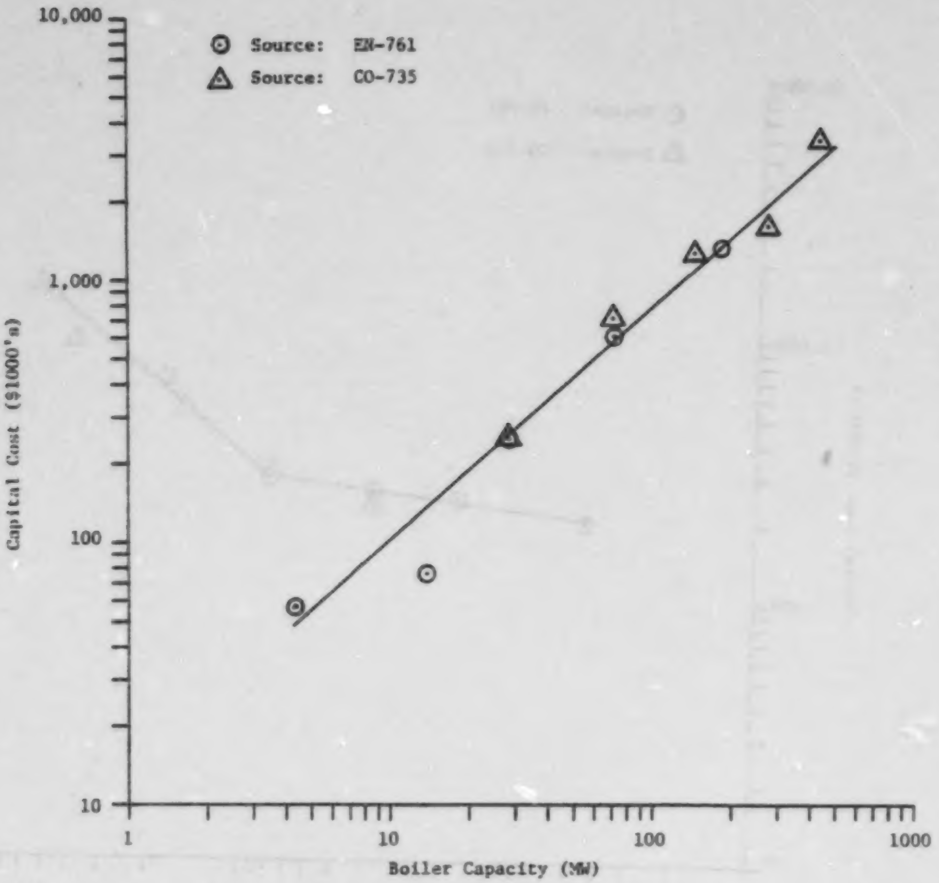


Figure 4-11. Estimated capital costs for coal handling and storage (1977$).

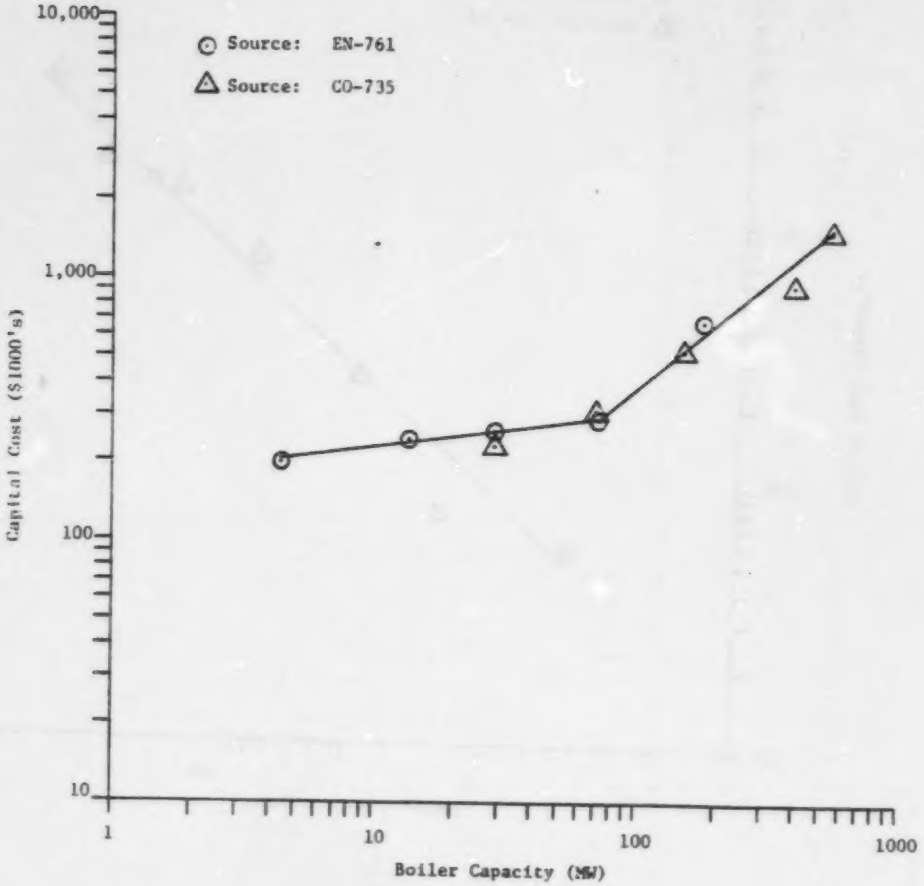


Figure 4-12. Estimated costs for ash handling equipment (1977$).

modification are approximately 40 percent of the costs of a new, coal-fired boiler. If the cost of replacing the capacity which is lost by converting from gas/oil to coal is added to the estimated costs of modification, total cost to convert to coal and maintain full capacity is 97 percent of the cost of a new, coal-fired boiler.

The costs presented above are just estimates, but it appears the costs of boiler modification coupled with the costs of replacing lost capacity make conversion of a gas/oil-fired boiler to coal impractical.

Operating and maintenance costs--The additional operating and maintenance (O&M) costs which are incurred when a gas or oil boiler switches to coal have not been estimated. However, a close approximation of the increased costs is the difference between the O&M costs of a gas/oil-fired boiler and the O&M costs of a coal-fired boiler. Figure 4-13 presents this difference for various sizes of boilers. As shown, O&M costs will increase between 120,000 dollars per year for a 4.4 MW boiler to 550,000 dollars per year for a 176 MW boiler.

The change in O&M costs which results from a switch to coal represents a 4 to 5 fold increase. The main reason for this large cost increase between coal- and gas/oil-fired boilers is the difference in the labor requirements for boilers firing these fuels. A coal boiler requires additional personnel to operate the boiler as well as extra operating personnel for the coal and ash handling equipment (EN-761).

4.3.2.3 Environmental Impact--

In general, conversion of a gas/oil-fired boiler to coal will result in an increase of uncontrolled emissions. But there are several types of pollution control systems which can be used to limit emission increases or actually reduce emissions. The following discussion examines the changes in emissions of the five criteria pollutants: particulates, sulfur dioxide, nitrogen oxides, carbon monoxide, and hydrocarbons. In addition, techniques

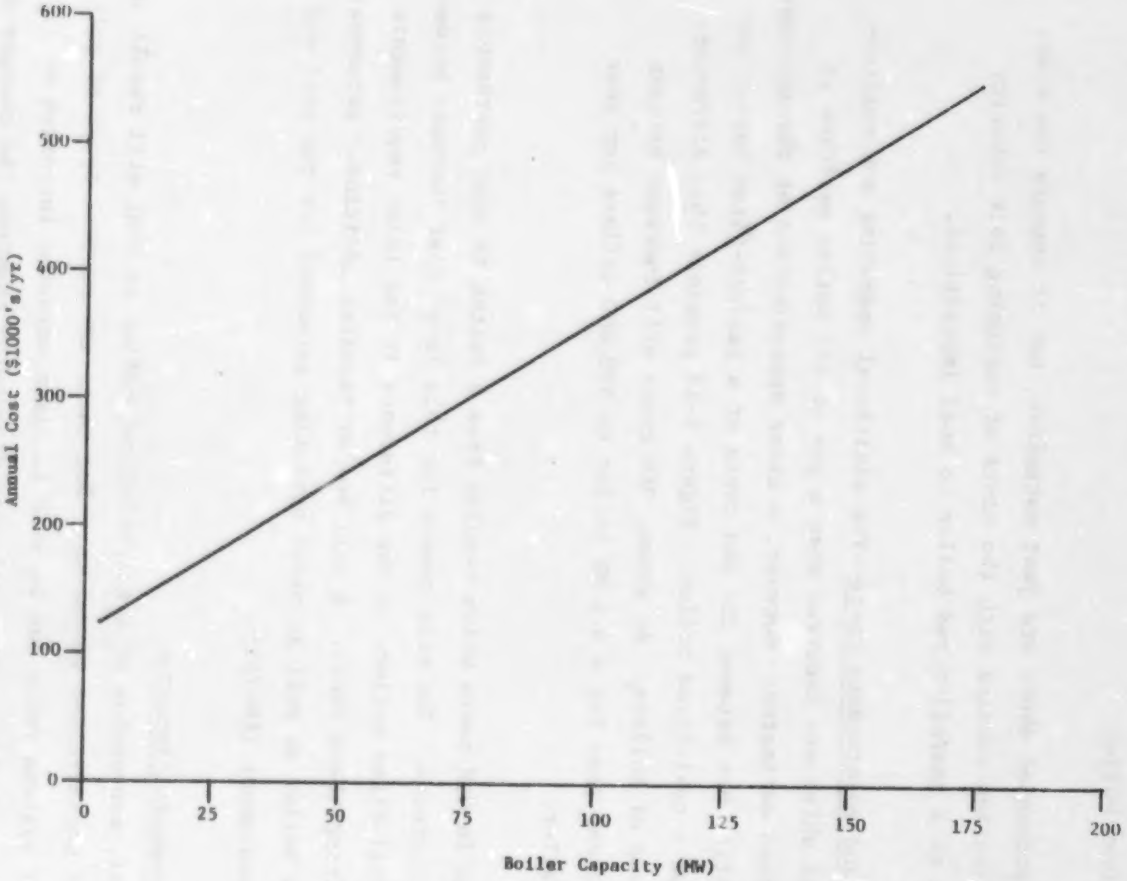


Figure 4-13. Estimated increase in operating and maintenance costs which results from a switch to coal.
Load factor: (4000 hrs/yr at 100 percent capacity).
Source: EN-761

to control these emissions are identified. And the applicability of these techniques to a converted boiler is examined.

Estimated emission changes--The change in emissions which results when a gas/oil-fired boiler is converted to coal can be estimated by the difference in emissions between a gas/oil-fired boiler and coal-fired unit. Table 4-12 presents the estimated change in uncontrolled emissions for 36 possible boiler conversions. As shown, there are significant increases in particulate, sulfur dioxide, and nitrogen oxide emissions for 29 of the 36 cases. But there are actually some significant emission reductions in 6 of the 36 cases. These reductions are in sulfur dioxide emissions, and they result from converting to low-sulfur coal from high-sulfur oil.

Pollution control equipment--A detailed examination of pollution control techniques which are applicable to industrial boilers is being conducted as part of the study to develop background information to support industrial boiler NSPS. The following discussion examines special problems which arise in applying pollution control to boilers which have switched fuels from gas/oil to coal.

The primary consideration in applying pollution controls to industrial boilers which have switched fuel from gas/oil to coal is the space available for installation of control equipment. In most cases, space is simply not available and installation of pollution control equipment is impractical if not impossible. The case of a boiler which was originally designed to burn coal may be different. If consideration was given to pollution control during design, or if control equipment was included in the original installation, it may be possible to add suitable equipment to the boiler. This is especially true in the case of particulate control equipment.

TABLE 4-12. ESTIMATED EMISSION CHANGE DUE TO FUEL SWITCHING[1]

Boiler Configuration After Fuel Switch	Pollutant	Change in Emission Rate (nanograms/Joule)								
		Natural Gas[2] To			Distillate Oil[2] To			Residual Oil[2] To		
		Coal #1[2]	Coal #2[2]	Coal #3[2]	Coal #1	Coal #2	Coal #3	Coal #1	Coal #2	Coal #3
Package, Watertube, Underfeed Stoker										
	Fly ash	945.8	537.4	601.9	945.8	537.4	601.9	902.8	494.4	558.9
	SO_2	1805.7	386.9	386.9	1590.7	172.0	172.0	494.4	(967.3)	(967.3)
	NO_x as NO_2	111.8	111.8	111.8	68.8	68.8	68.8	21.5	21.5	21.5
	CO	29.2	23.6	37.4	21.1	15.5	29.2	21.1	15.5	29.2
	Hydrocarbons as CH_4	16.8	14.2	21.1	15.0	12.5	19.3	15.0	12.5	19.3
Package, Watertube, Chaingrate Stoker										
	Fly ash	859.8	472.9	537.4	859.8	472.9	537.4	816.9	429.9	494.4
	SO_2	2540.6	537.4	515.9	2235.6	322.4	300.9	1096.3	(816.9)	(838.3)
	NO_x as NO_2	64.5	64.5	64.5	21.5	21.5	21.5	(258.0)	(258.0)	(258.0)
	CO	29.2	23.6	37.4	21.1	15.5	29.2	21.1	15.5	29.2
	Hydrocarbons as CH_4	16.8	14.2	21.1	15.0	12.5	19.3	15.0	12.5	19.3
Field Erected, Watertube, Spreader Stoker										
	Fly ash	1074.8	601.9	687.9	1074.8	601.9	687.9	1031.8	558.9	644.9
	SO_2	2536.5	558.9	537.4	2321.6	343.9	322.4	1182.3	(795.4)	(816.9)
	NO_x as NO_2	206.4	206.4	206.4	145.3	145.3	145.3	116.1	116.1	116.1
	CO	29.2	23.6	37.4	21.1	15.5	29.2	21.1	15.5	29.2
	Hydrocarbons as CH_4	16.8	14.2	21.1	15.0	12.5	19.3	15.0	12.5	19.3
Field Erected, Watertube, Pulverized Coal										
	Fly ash	2751.5	1547.7	1719.7	2751.5	1547.7	1719.7	2708.5	1504.7	1676.7
	SO_2	1719.7	386.9	386.9	1504.7	172.0	172.0	150.5	(1182.3)	(1182.3)
	NO_x as NO_2	210.7	210.7	210.7	167.7	167.7	167.7	120.4	120.4	120.4
	CO	10.7	8.2	15.0	(4.7)	(7.3)	(0.4)	(4.7)	(7.3)	(0.4)
	Hydrocarbons as CH_4	4.3	3.4	5.6	1.3	0.4	2.6	1.3	0.4	2.6

[1] Source: (PE-348)

[2] Fuel analyses are:

	Natural Gas	Distillate Oil	Residual Oil	Coal #1	Coal #2	Coal #3
Sulfur	Trace	0.5 percent	3.0 percent	3.5 percent	0.9 percent	0.6 percent
Ash	Trace	Trace	0.1 percent	10.6 percent	6.9 percent	5.4 percent
HHV	37.3 (MJ/m^3)	38.8 (MJ/ℓ)	41.8 (MJ/ℓ)	37,500 (kJ/kg)	32,150 (kJ/kg)	22,370 (kJ/kg)

TABLE 4-12. Continued

Boiler Configuration After Fuel Switch	Pollutant	Change in Emission Rate (lb/10^6 Btu)								
		Natural Gas[2] To			Distillate Oil[2] To			Residual Oil[2] To		
		Coal #1[2]	Coal #2[2]	Coal #3[2]	Coal #1	Coal #2	Coal #3	Coal #1	Coal #2	Coal #3
Package, Watertube, Underfeed Stoker										
	Fly ash	2.2	1.25	1.4	2.2	1.25	1.4	2.1	1.15	1.3
	SO_2	4.2	0.9	0.9	3.70	0.4	0.4	1.15	(2.25)	(2.25)
	NO_x as NO_2	0.26	0.26	0.26	0.16	0.16	0.16	0.05	0.05	0.05
	CO	$6.8x10^{-2}$	$5.5x10^{-2}$	$8.7x10^{-2}$	$4.9x10^{-2}$	$3.6x10^{-2}$	$6.8x10^{-2}$	$4.9x10^{-2}$	$3.6x10^{-2}$	$6.8x10^{-2}$
	Hydrocarbons as CH_4	$3.9x10^{-2}$	$3.3x10^{-2}$	$4.9x10^{-2}$	$3.5x10^{-2}$	$2.9x10^{-2}$	$4.5x10^{-2}$	$3.5x10^{-2}$	$2.9x10^{-2}$	$4.5x10^{-2}$
Package, Watertube, Chaingrate Stoker										
	Fly ash	2.0	1.1	1.25	2.0	1.1	1.25	1.9	1.0	1.15
	SO_2	5.7	1.25	1.20	5.2	0.75	0.7	2.55	(1.9)	(1.95)
	NO_x as NO_2	0.15	0.15	0.15	0.05	0.05	0.05	(0.6)	(0.6)	(0.6)
	CO	$6.8x10^{-2}$	$5.5x10^{-2}$	$8.7x10^{-2}$	$4.9x10^{-2}$	$3.6x10^{-2}$	$6.8x10^{-2}$	$4.9x10^{-2}$	$3.6x10^{-2}$	$6.8x10^{-2}$
	Hydrocarbons as CH_4	$3.9x10^{-2}$	$3.3x10^{-2}$	$4.9x10^{-2}$	$3.5x10^{-2}$	$2.9x10^{-2}$	$4.5x10^{-2}$	$3.5x10^{-2}$	$2.9x10^{-2}$	$4.5x10^{-2}$
Field Erected, Watertube, Spreader Stoker										
	Fly ash	2.5	1.4	1.6	2.5	1.4	1.6	2.4	1.3	1.5
	SO_2	5.9	1.3	1.25	5.4	0.8	0.75	2.75	(1.85)	(1.9)
	NO_x as NO_2	0.48	0.48	0.48	0.38	0.38	0.38	0.27	0.27	0.27
	CO	$6.8x10^{-2}$	$5.5x10^{-2}$	$8.7x10^{-2}$	$4.9x10^{-2}$	$3.6x10^{-2}$	$6.8x10^{-2}$	$4.9x10^{-2}$	$3.6x10^{-2}$	$6.8x10^{-2}$
	Hydrocarbons as CH_2	$3.9x10^{-2}$	$3.3x10^{-2}$	$4.9x10^{-2}$	$3.5x10^{-2}$	$2.9x10^{-2}$	$4.5x10^{-2}$	$3.5x10^{-2}$	$2.9x10^{-2}$	$4.5x10^{-2}$
Field Erected, Watertube, Pulverized Coal										
	Fly ash	6.4	3.6	4.0	6.4	3.6	4.0	6.3	3.5	3.9
	SO_2	4.0	0.9	0.9	3.5	0.4	0.4	0.35	(2.75)	(2.75)
	NO_x as NO_2	0.49	0.49	0.49	0.39	0.39	0.39	0.28	0.28	0.28
	CO	$2.5x10^{-2}$	$1.9x10^{-2}$	$3.5x10^{-2}$	$(1.1x10^{-2})$	$(1.7x10^{-2})$	$(0.1x10^{-2})$	$(1.1x10^{-2})$	$(1.7x10^{-2})$	$(0.1x10^{-2})$
	Hydrocarbons as CH_4	$1.0x10^{-2}$	$0.8x10^{-2}$	$1.3x10^{-2}$	$0.3x10^{-2}$	$0.1x10^{-2}$	$0.6x10^{-2}$	$0.3x10^{-2}$	$0.1x10^{-2}$	$0.6x10^{-2}$

[1] Source: (PE-348)

		Natural Gas	Distillate Oil	Residual Oil	Coal #1	Coal #2	Coal #3
[2] Fuel Analyses are:	Sulfur	Trace	0.5 percent	3.0 percent	3.5 percent	0.9 percent	0.6 percent
	Ash	Trace	Trace	0.1 percent	10.6 percent	6.9 percent	5.4 percent
	HHV	37.3 (MG/m^3)	38.8 (MG/ℓ)	41.8 (MJ/ℓ)	27,500 (kJ/kg)	32,150 (kJ/kg)	22,370 (kJ/kg)

Particulate emissions - An industrial boiler which converts to coal firing will probably require particulate control equipment. The most applicable control equipment includes fabric filters and electrostatic precipitators. The major limitation to application of this equipment is the space required for installation. In addition, the cost of retrofitting control equipment may be prohibitive.

Sulfur dioxide emissions - It is unlikely that a boiler which converts from gas/oil to coal will have the space for installation of a flue gas desulfurization system. Therefore, it appears that use of low sulfur coal is the most applicable method of reducing SO_2 emissions from a gas/oil-fired boiler which has been converted to coal.

Nitrogen oxide emissions - Combustion modifications can be used to reduce NO_x emissions from converted boilers, and their applicability is not limited but their effectiveness is. Total NO_x reductions will range from 30 to 50 percent, depending on boiler type (BL-147). Flue gas treatment is not applicable to gas/oil-fired units which convert to coal. Space and cost factors make application of FGT impractical if not impossible.

4.3.3 Coal-Oil Mixture Combustion

Conversion of a gas/oil-fired boiler to coal firing can prove very difficult and costly. In fact, from a technical and economic standpoint it appears that boiler replacement is more feasible than converting an existing gas/oil boiler to coal. But there is one method for firing coal in an existing gas/oil boiler which appears to be potentially attractive. This is coal-oil mixture (COM) combustion.

Combustion of a coal-oil mixture may offer a near-term method of firing coal in existing gas/oil boilers. It appears that many existing boilers can be converted to COM firing with a minimum of modification, derating, outage time, and cost. However, the technology of COM combustion has not been demonstrated for long-term use and some unanswered questions remain.

The following discussion examines the COM combustion process, its status of development, and potential process problems which have not been resolved. In addition, estimates are presented for the costs of required boiler modifications, the cost of preparing COM, and emissions from COM combustion in an existing boiler.

4.3.3.1 Process Description - Coal-Oil Combustion--

Coal-oil mixture combustion appears to be a promising method of switching existing gas/oil-fired boilers to coal. However, there are several factors which must be considered in using COM. These factors include:

1) COM preparation,
2) Boiler modifications,
3) Status of development,
4) Costs, and
5) Pollution control.

The following discussion examines the first three of these factors in detail. Costs are presented in Section 4.3.3.2 and pollution control is discussed in Section 4.3.3.3.

COM Preparation--Preparation of coal-oil mixture is a fairly complex process although commercially available equipment is employed. The preparation process requires facilities for receiving, storing, handling, and pulverizing coal. In addition, oil storage facilities and equipment for mixing the coal and oil are needed. Because of the preparation process requirements, preliminary analyses have indicated that operators of small industrial boilers will not use on-site COM preparation. Only operators of large boilers will actually prepare COM on-site while smaller facilities will purchase COM from a large, central facility (BE-531).

The actual economic breakpoint between on and off-site preparation has not been determined. One study prepared by the Department of Energy indicates that a 35 MW (∿125 x 10^6 Btu/hr) boiler is too small to accommodate on-site COM preparation, but a 180 MW (∿625 x 10^6 Btu/hr) boiler will support a COM preparation plant (BE-531).

Coal-oil mixture is prepared by first pulverizing coal to a very fine powder. This powdered coal is then mixed with residual fuel oil to form a fuel slurry which can be pumped like oil and fired by modified conventional oil burners.

The degree of pulverization required to produce a stable coal-oil mixture will vary depending on the coal, the oil, and any additives which are included. A study conducted by General Motors, Inc. indicated that stable coal-oil mixtures can be prepared with pulverized coal which ranges in size from 15 μm to 75 μm (4.9×10^{-5} to 2.5×10^{-4} ft) (BR-493).

Currently, there are three different coal pulverization systems being examined for preparation of COM. One uses conventional coal pulverizers. A second uses a wet ball mill which grinds the coal with residual oil. And the third system uses wet grinding of coal in a high-speed disperser.

The maximum concentration of coal which can be used in a coal-oil mixture will vary depending on the application. Tests have been conducted with coal concentrations ranging from 20 to 50 weight percent.

Coal concentration will have a significant impact on the performance of the boiler and the costs of COM firing. Obviously, a higher coal concentration may adversely impact system performance. Higher coal concentrations increase fuel viscosity and therefore make COM more difficult to pump. In addition, higher concentrations can result in erosion of pipes and burners, increased emissions of particulates and sulfur dioxide, and boiler derating.

To date, some problems have been encountered with the stability of coal-oil mixtures. During storage, coal can settle out of the COM and produce a non-homogenous mixture. This can cause problems by plugging lines and in some tests, it has resulted in tripping the boiler.

There are several approaches which can be taken to assure COM stability. The first is simply to prepare a mixture which will remain homogenous for an indefinite period of time. This can be accomplished by pulverizing the coal to below 15 μm (4.9×10^{-5} ft) or by addition of emulsifying agents which prevent the coal from settling out of the mixture. Both techniques are expensive and may not necessarily represent an optimum solution to the stability problem.

A second approach to COM stability is to provide continuous agitation of the mixture during storage and transportation. This approach is feasible and provides for a lower cost mixture, but operational difficulties occur. Installation and maintenance of the agitation system is required. In addition, provisions must be made for flushing of fuel lines during periods when the boiler is down.

Finally, the COM can be prepared as a remixable liquid. This approach employs an additive to prevent hard packing of the coal during storage and transportation. The COM can then be mixed to uniformity prior to pumping or combustion.

Boiler modifications--Coal-oil mixtures can be fired in existing boilers using conventional oil burners. However, some modifications of the boiler are required, and the extent of the modifications will depend on the type of boiler which is being converted.

Conversion of a gas boiler to COM firing will require significant modifications. These modifications will be similar to those required to convert a gas-fired unit to residual oil-firing. They include.

1) Installation of COM supply and storage systems.
2) Installation of oil burners.
3) Modification of furnace or superheater to obtain design steam temperatures.
4) Addition of soot blowers to remove ash deposits from convection tubes.
5) Modification or replacement of the economizer to prevent plugging of the gas passage.
6) Modification of the air preheater to prevent acid corrosion.
7) Installation an ash removal and handling system.

A more detailed examination of these modifications appears in Section 4.2.1.1.

The modifications required to convert a distillate oil boiler to COM firing will not be as significant as those required to convert from gas firing to COM with some modification. Existing oil storage and supply lines can be used. Addition of agitators to the storage facilities may be required.

Actual modification of the boiler internals will be similar to those for a gas to COM switch. Soot blowers and ash handling systems will be needed. In addition, modification of the superheater, preheater, and economizer may be necessary, depending on the specific boiler design.

Conversion of a residual oil boiler to COM firing is the most feasible fuel switch of the three. And it can be done with a minimum of modifications. Soot blowers and ash handling systems are already available in most residual oil boilers and the existing storage, fuel supply lines, and burners can be used.

Modifications required to switch from residual oil to COM include installation of fuel strainers in supply lines to capture oversize particles or agglomerates and replacement of existing pumps with equipment designed to handle an abrasive slurry. If the COM used has not been stablizied, an agitation system must be added to the oil storage tanks. In addition, fuel supply lines may need to be rerouted to eliminate areas where settling can occur and the oil burners may require modification to prevent blockages in restricted passages.

Status of development--Coal-oil mixture combustion was first proposed in 1879, and it has been examined several times since then. However, in the past, the availability of relatively inexpensive gas and oil has limited COM development.

Recently, gas and oil prices have increased and supplies have become uncertain. As a result, there is renewed interest in COM combustion. In 1974, General Motors (GM) began testing COM as an industrial boiler fuel, and in 1975, GM received funds from the U.S. Energy Research and Development Administration (now U.S. Department of Energy - DOE) to continue research into COM firing. Since that time, DOE has increased its involvement in COM combustion.

Currently, there are four COM research projects in progress and the GM project has been completed. The specific details of these projects are presented in Table 4-13. As shown, these projects are examining COM firing in several existing boilers including industrial units which were originally designed for gas/oil firing.

To date, research on COM combustion has indicated that coal-oil mixtures can be fired in existing equipment with a minimum of modification. However, further development of COM combustion is required before the application of this process to industrial boilers will expand.

TABLE 4-13. CHARACTERISTICS OF COAL-OIL MIXTURE RESEARCH PROJECTS[1]

Prime Contractor	Application	Test Unit Capacity	Fuel		Coal Concentration (Percent)	Coal Use (MTon/day)	COM Preparation
			Oil	Coal			
Interlake, Inc.	Blast Furnace Injection	1100 MTon/day	No. 6	Illinois	50	46	On Site Wet-Grinding Disperser with Additive
New England Power Service Company	Oil-fired Utility Boiler Designed for Coal	225 MW	No. 6	Virginia West Virginia Kentucky	30	145	On Site Existing Pulverizers with Mixer and Additive
Acurex Corporation	Oil-fired Industrial Boiler Designed for Gas/Oil	30 MW	No. 6	Virginia	35	22	On Site Wet-Grinding Ball Mill with Additive
General Motors	Oil-fired Industrial Boiler Designed for Gas/Oil	44 MW	No. 6	Pittsburgh No. 8	50	79	On Site Homogenation of Water-In-Oil with Additive
Pittsburgh Energy Research Center (DOE)	Oil-fired Industrial Boiler Designed for Gas/Oil	9 MW	No. 6	Bituminous Sub-bituminous	40	6	On Site Mixtures Prepared with Additive and without Additive

[1] Source: (FR-277)

Some areas which require further development are:

1) The preparation of stable coal-oil mixtures has not been optimized.
2) The erosion of pumps, valves, and piping by coal-oil mixtures has not been quantified.
3) The applicability of commercial instrumentation for control of COM firing has not been evaluated.
4) The feasibility of transporting COM from a central facility to a plant site using conventional fuel handling systems has not been investigated.

It is expected that the current DOE programs will develop these areas of COM preparation and firing.

4.3.3.2 Costs of Coal-Oil Mixture Combustion--

Combustion of coal-oil mixture in an existing gas or oil-fired boiler is a promising method for switching from gas/oil to coal. However, because COM preparation and combustion technology are in an early stage of development, only tentative cost estimates have been prepared. More accurate costs should be developed as part of DOE's COM research program but this work is not completed. As a result, the costs presented in this report are estimates based on engineering judgement.

Capital costs--There are two distinct capital costs associated with COM combustion; the costs of boiler modification required to permit COM firing in an existing unit and the costs of equipment required to prepare COM from coal and oil feedstocks.

Figure 4-14 presents capital cost estimates for the boiler modifications required to fire COM. Costs are presented as a function of size, and as illustrated, they increase exponentially with size. The value of the exponent is 0.9. These costs are from a study prepared by Arthur G. McKee and Company (CH-476). Included in the estimates are the costs of particulate

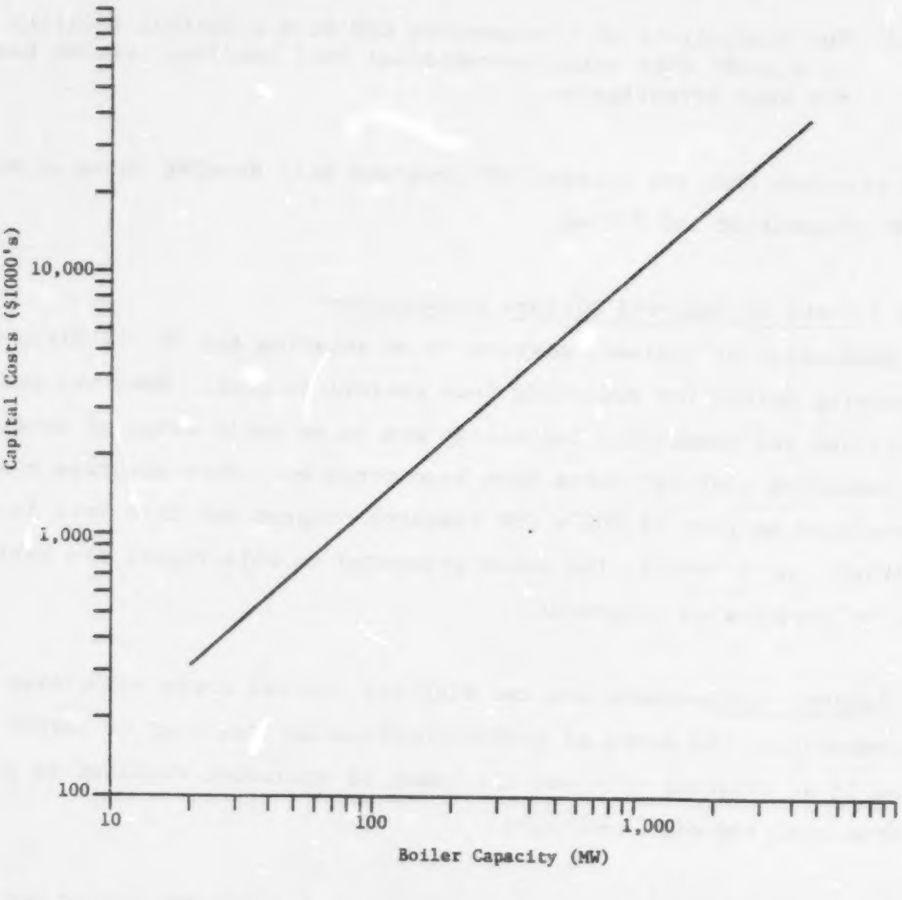


Figure 4-14. Estimated cost of boiler modifications required to fire COM ($1978).

Source: CH-476

control equipment, soot blowers, ash handling equipment, boiler modifications. and COM storage and handling equipment. The costs required to replace any capacity which may be lost due to boiler derating are not included. This cost may exceed the costs of the boiler modifications.

The capital costs presented in Figure 4-14 are for conversion of a gas/oil-fired boiler to COM. And these costs represent approximately 12 percent of the costs of a new, coal-fired boiler. However, these costs are higher than the costs of converting a residual oil boiler to COM firing. A residual oil boiler already has soot blowers, ash handling equipment, and oil handling and storage facilities which can be used after conversion. In addition, particulate control equipment may be available.

Figure 4-15 presents an estimate of boiler modification costs for a conversion from residual oil to COM. These costs were estimated by DOE's Pittsburgh Energy Research Center. The estimate includes the costs of all modifications required to retrofit a residual oil boiler to COM firing, but no pollution control costs are included.

A comparison of the cost for converting a gas/oil boiler to COM with the cost of converting a residual boiler to COM firing shows that the cost of the latter conversion is approximately 10 percent of the cost of the former. This means that the capital costs of converting a residual oil boiler to COM are only a small fraction of the capital costs of a new coal-fired boiler.

A second capital cost associated with a switch from gas/oil to COM is the cost of a COM preparation facility. These costs include capital costs for coal handling and storage, oil handling and storage, coal pulverization, and coal-oil mixing equipment. Figure 4-16 compares capital cost estimates of a COM preparation plant with the costs of a new, pulverized coal-fired boiler. As shown, COM preparation plant costs are between 10 and 20 percent of the costs of a new, coal-fired unit.

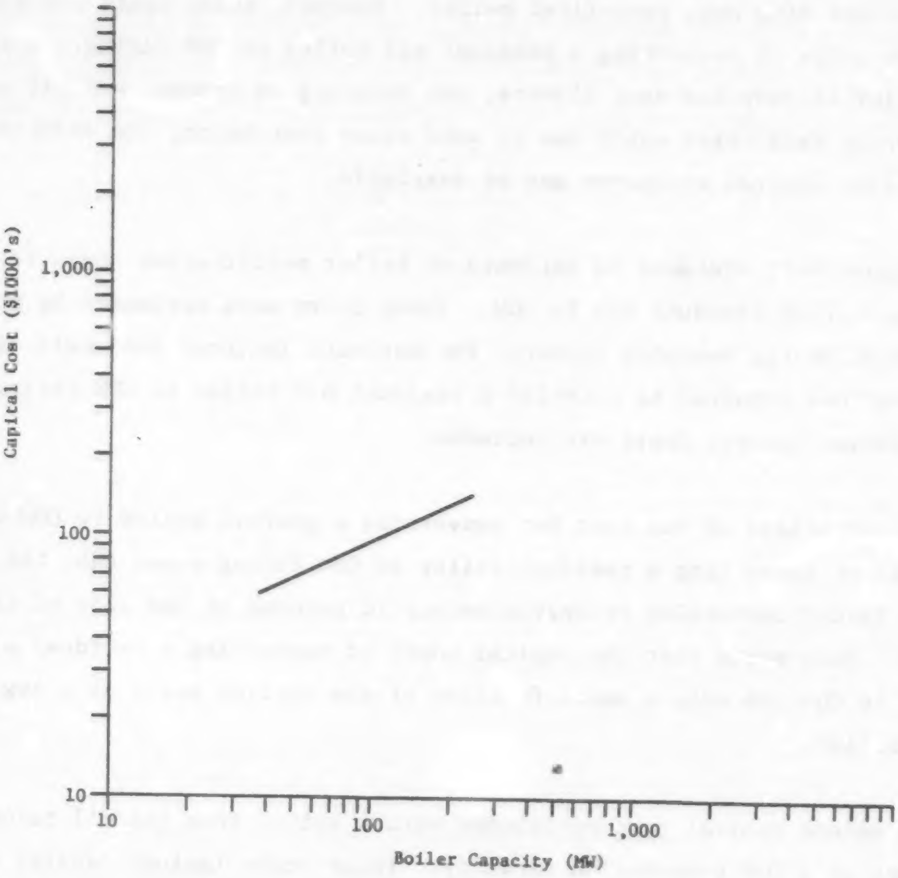


Figure 4-15. Estimated capital costs for conversion of a residual oil boiler to COM firing ($1978).

Source: BE-531

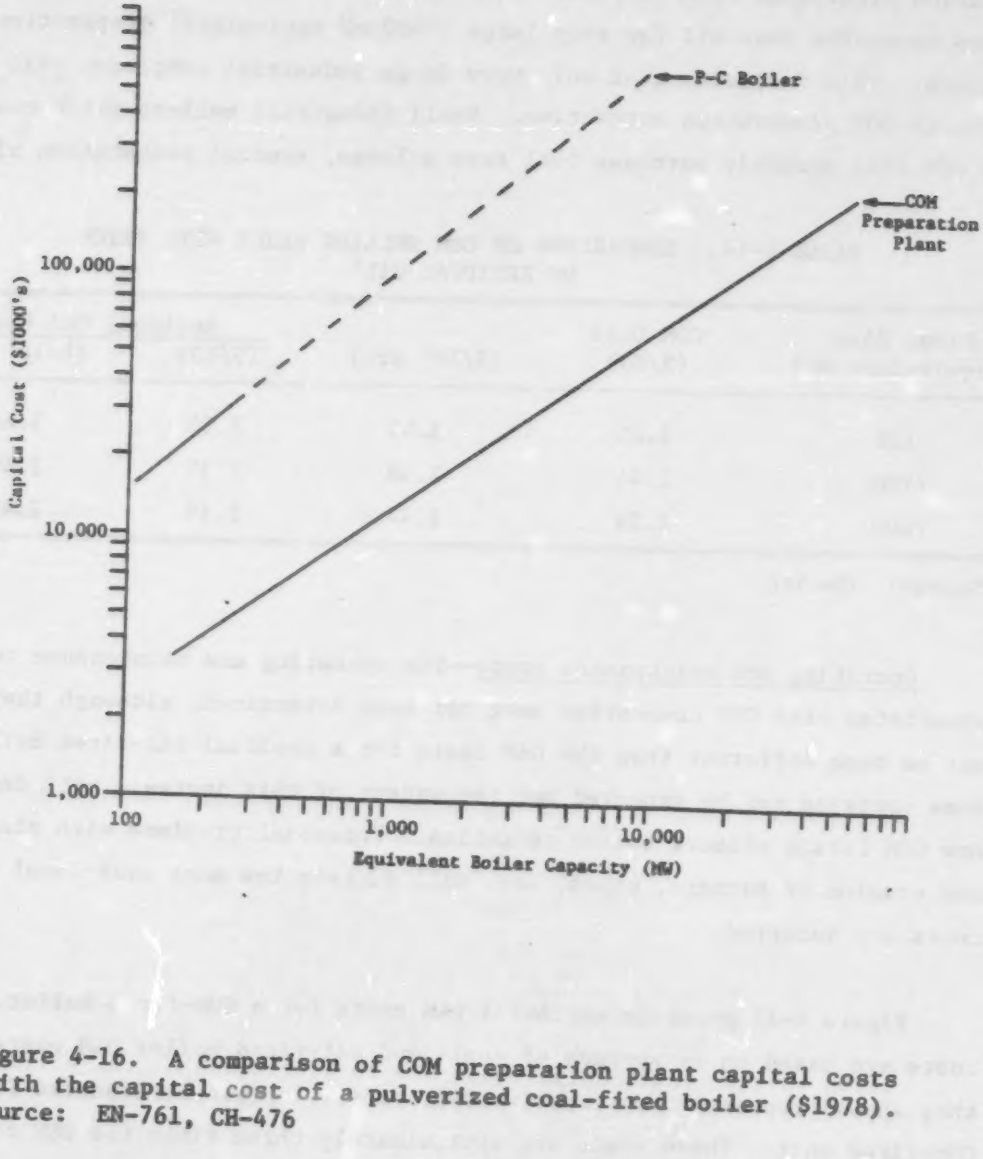


Figure 4-16. A comparison of COM preparation plant capital costs with the capital cost of a pulverized coal-fired boiler ($1978). Source: EN-761, CH-476

The COM preparation plant costs presented are only for large facilities (greater than 100 MW equivalent - ~350 x 10^6 Btu/hr). This is because on-site COM preparation is not economical for small industrial boilers. Table 4-14 compares estimated selling prices for COM as a function of preparation plant size with the cost of residual oil. As illustrated, COM is less expensive than oil for very large (7400 MW equivalent) preparation plants. This indicates that only very large industrial complexes will find on-site COM preparation attractive. Small industrial boilers which convert to COM will probably purchase fuel from a large, central preparation plant.

TABLE 4-14. COMPARISON OF COM SELLING PRICE WITH PRICE OF RESIDUAL OIL[1]

Plant Size (equivalent MW)	COM Cost ($/GJ)	($/$10^6$ Btu)	Residual Oil Cost ($/GJ)	($/$10^6$ Btu)
120	3.25	3.43	2.35	2.48
1100	2.44	2.58	2.35	2.48
7400	2.29	2.47	2.35	2.48

[1] Source: CH-476

Operating and maintenance costs--The operating and maintenance costs associated with COM combustion have not been determined, although they should not be much different than the O&M costs for a residual oil-fired boiler. Some increase can be expected but the extent of this increase will depend on how COM firing effects boiler operation. Potential problems with plugging and erosion of burners, pipes, etc. will dictate how much additional O&M costs are incurred.

Figure 4-17 presents estimated O&M costs for a COM-fired boiler. These costs are based on an average of coal- and oil-fired boiler O&M costs. And they should represent conservative O&M costs which can be expected for a COM-fired unit. These costs are approximately three times the O&M costs of a residual oil boiler.

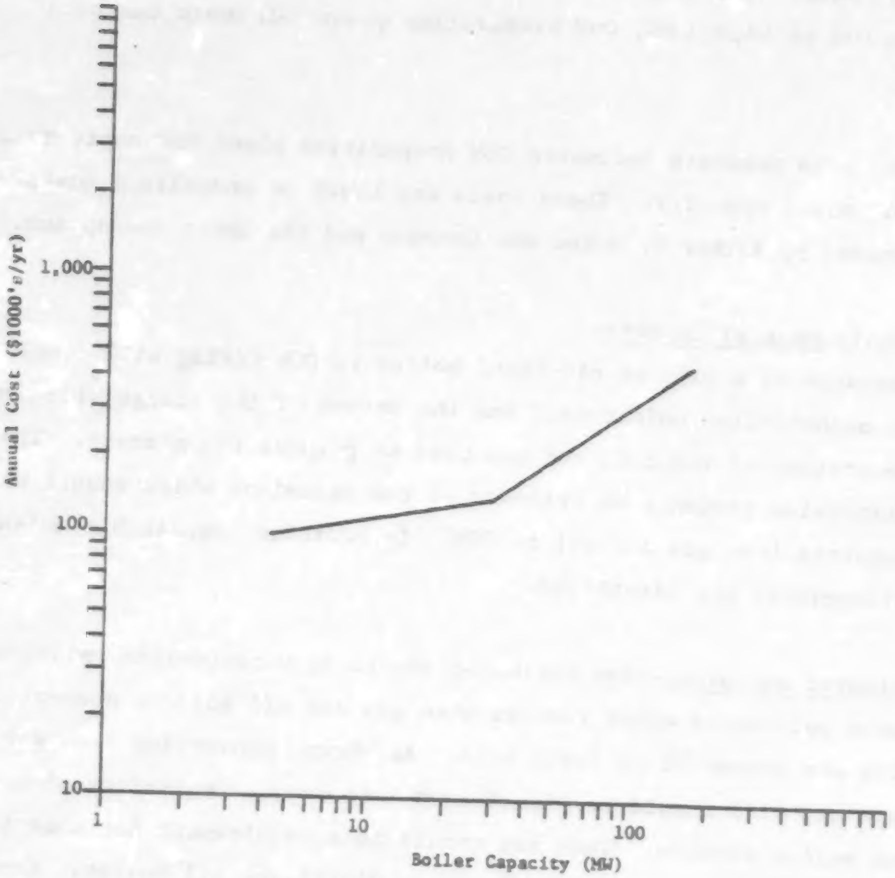


Figure 4-17. Estimated operating and maintenance costs for a COM-fired boiler.
Load factor: (4000 hrs/yr at 100 percent capacity).
Source: EN-761

The O&M costs of a COM preparation facility have been estimated by DOE's Pittsburgh Energy Research Center. This estimate was for a large (13,000 MW) facility, and O&M costs were approximately 2.3 percent of annualized costs. Assuming this percentage is accurate over the size range from 100 to 13,000 MW, COM preparation plant O&M costs can be estimated.

Figure 4-18 presents estimated COM preparation plant O&M costs as a function of plant capacity. These costs are based on annualized costs which were estimated by Arthur G. McKee and Company and the above assumption.

4.3.3.3 Environmental Impact--

Conversion of a gas- or oil-fired boiler to COM firing will result in a change in uncontrolled emissions. And the extent of the change will depend on the properties of the coal and oil used to prepare the mixture. The following discussion presents an estimate of the emissions which result when a boiler converts from gas and oil to COM. In addition, applicable emission control techniques are identified.

Estimated emissions--The estimated change in uncontrolled emissions of criteria pollutants which results when gas and oil boilers convert to COM firing are presented in Table 4-15. As shown, converting from gas or distillate oil will result in significant increases in emissions of particulates and sulfur dioxide. This may result in a requirement for some type of particulate and SO_2 control on a gas or distillate oil boiler. Conversion of a residual oil boiler to COM firing will result in a significant increase in uncontrolled particulate emissions. But, COM firing lowers SO_2 emissions in the two cases where low-sulfur coal is used to prepare the fuel. This indicates that some additional particulate control may be required after conversion but if low-sulfur coal is used, no additional SO_2 control equipment will be necessary.

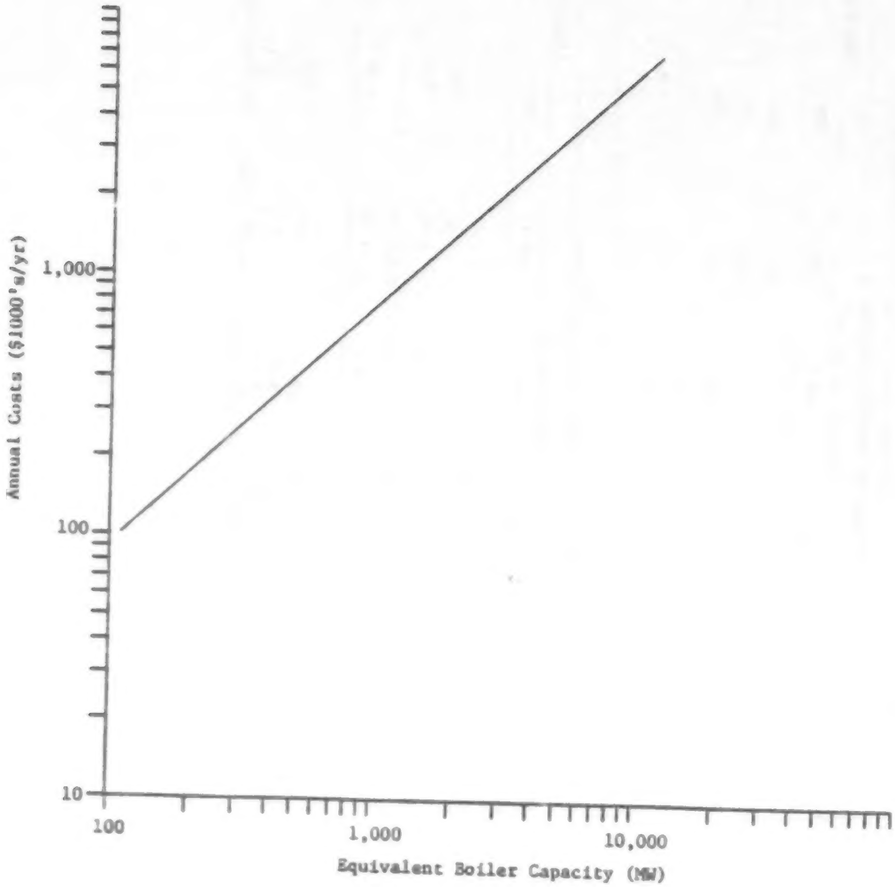


Figure 4-18. Estimated operating and maintenance costs for a COM preparation plant.
Load Factor: (6400 hrs/yr at 100 percent capacity).
Source: CH-476

TABLE 4-15. ESTIMATED CHANGE IN EMISSIONS WHICH RESULTS WHEN GAS AND OIL BOILERS SWITCH TO COM FIRING[1]

Pollutant	Change in Emission Rate (ng/J)								
	Gas to[2]			Distillate Oil to[2]			Residual Oil to[2,3]		
	COM 1	COM 2	COM 3	COM 1	COM 2	COM 3	COM 1	COM 2	COM 3
Particulates	1084	671	607	1084	671	607	1045	632	568
Sulfur dioxide	1497	942	1020	1285	731	808	147	(408)	(330)
Nitrogen oxide as NO_2	151	151	151	108	108	108	60	60	60
Carbon monoxide	8.5	7.6	9.4	0.3	(0.6)	1.5	0.3	(0.6)	1.5
Hydrocarbons as CH_4	2.6	2.3	2.9	0.8	0.5	1.2	0.8	0.5	1.2

Pollutant	Change in Emission Rate (lb/10^6 Btu)								
	Gas to[2]			Distillate Oil to[2]			Residual Oil to[2,3]		
	COM 1	COM 2	COM 3	COM 1	COM 2	COM 3	COM 1	COM 2	COM 3
Particulates	2.5	1.6	1.4	2.5	1.6	1.4	2.4	1.5	1.3
Sulfur dioxide	3.5	2.2	2.4	3.0	1.7	1.9	0.4	(0.9)	(0.7)
Nitrogen oxide as NO_2	0.35	0.35	0.35	0.25	0.25	0.25	0.14	0.14	0.14
Carbon monoxide	2.0×10^{-2}	1.8×10^{-2}	2.3×10^{-2}	0.1×10^{-2}	(0.1×10^{-2})	0.4×10^{-2}	0.1×10^{-2}	(0.1×10^{-2})	0.4×10^{-2}
Hydrocarbons as CH_4	6.0×10^{-3}	5.4×10^{-3}	6.7×10^{-3}	1.8×10^{-3}	1.2×10^{-3}	2.5×10^{-3}	1.8×10^{-3}	1.2×10^{-3}	2.5×10^{-3}

[1] Based on emission factors in PB-348

[2] Fuel analyses are:

	Natural Gas	Distillate Oil	Residual Oil	COM 1	COM 2	COM 3
Sulfur	Trace	0.5 percent	3.0 percent	3.25	1.95	1.8
Ash	Trace	Trace	0.1 percent	5.35	3.5	2.25
HHV	37.3(MJ/m^3)	38.8(MJ/ℓ)	41.8(MJ/ℓ)	35,900(kJ/kg)	38,200(kJ/kg)	33,300(kJ/kg)

[3] The specific gravity of residual oil is assumed to be 0.95.

Pollution control equipment--A detailed examination of pollution control equipment which is available for controlling emissions from industrial boilers is being prepared as part of the study to develop background information for industrial boiler NSPS. The following discussion briefly examines the applicability of available pollution control to gas- and oil-fired boilers which have switched to COM firing.

Particulate emissions - A substantial increase in uncontrolled particulate emissions will result when a gas or oil boiler switches to COM combustion. As a result, some particulate control will probably be required to comply with state regulations. However, in many existing boilers, there is not adequate space available for control equipment to be installed. And, this may prohibit some boilers from switching from gas/oil to COM.

Electrostatioc precipitators and fabric filters can be used to control particulate emissions from COM-fired boilers. The choice of equipment will be site-specific and depend on characteristics of the boiler system. However, ESP's will probably be the predominant choice. This is because existing fan capacity should permit use of an ESP without modification while use of a fabrif filter could require additional fan capacity.

Sulfur dioxide emissions - A switch from gas or distillate oil to COM can result in a significant increase in SO_2 emissions from an industrial boiler. But a switch from high sulfur residual oil (3.0 percent sulfur) to COM prepared with low sulfur coal (less than 3.0 percent) can result in a reduction of SO_2 emissions. In the case in which SO_2 emissions decrease, no additional SO_2 control should be required. However, in the case where emissions increase, flue gas desulfurization may be needed.

Because of the difficulty of retrofitting an FGD system to an existing boiler, coupled with the increase in boiler system operating costs, the potential for decreased system reliability, and the need to dispose of byproduct or waste material produced by an FGD system, it does not appear that COM-fired boilers will use FGD to control SO_2 emissions. A more attractive and feasible alternative is to prepare coal-oil mixture using low-sulfur residual oil and low-sulfur coal. This can result in very low emissions of SO_2. If some reduction of SO_2 is required, the use of dry-alkali injection may be feasible.

Dry-alkali injection is an FGD system which does not require a scrubber. A dry alkali power (e.g., $NaHCO_3$) is injected into an existing flue gas duct and collected in a fabric filter. SO_2 reacts with the alkali material in the duct and the filter. SO_2 removal efficiencies between 50 and 80 percent have been reported (BE-465).

Nitrogen oxide emissions - Combustion modifications can be used to control nitrogen oxide emissions from boilers firing COM. A study conducted by Acurex Corporation indicated that combustion modifications which are currently used for pulverized coal-fired boilers are effective in reducing NO_x emissions produced by COM combustion. However, no general control efficiencies have been determined because both the chemical and physical properties of the COM impact the effectiveness of combustion modifications (BU-342).

4.3.4 Coal Gasification

Coal gasification is a process which can permit existing gas/oil-fired industrial boilers to switch to coal as a fuel source. This process converts coal from a solid to a gaseous fuel which has properties (e.g., heat release rate) similar to natural gas. And the coal-based gas can be burned in existing gas/oil-fired boilers with a minimum of modifications. The following discussion describes the gasification process and examines the boiler modifications required to convert an existing gas/oil-fired boiler to coal-based gas firing. In addition, estimates are presented for the costs of applying gasification to industrial boilers and for the change in emissions which results when coal-based gas is fired in an existing gas/oil boiler.

4.3.4.1 Process Description - Coal Gasification--

Gasification of coal and subsequent combustion of the fuel gas in an existing boiler is a technically feasible method of switching from gas or oil to a coal-based fuel. However, the gasification process is complex and there are many factors which must be examined when considering coal gasification as a method of switching fuels. Some of the more important are:

1) The type of gasification process employed,
2) Boiler modifications required to fire coal-based gas,
3) Gas purification requirements,
4) On-site vs. off-site gasification,
5) Costs of gasification, and
6) Pollution control required by a converted boiler.

The following discussion examines the first four of these factors in detail. Costs are discussed in Section 4.3.4.2 and pollution control is discussed in Section 4.3.4.3.

Type of gasification process--Coal gasification is the reaction of coal, water vapor, and oxygen to produce a gaseous fuel which has properties similar to natural gas. And the higher heating value (HHV)[1] of the fuel produced will depend on the type of gasification process used. There are three types of gasification processes; low-, medium-, and high-Btu gasification. Low-Btu gasification uses air as the source of oxygen in the gasification reaction and produces a fuel gas with a heating value of approximately 5.6 MJ/m^3 (150 Btu/scf). Medium-Btu gasification uses pure oxygen and produces a fuel gas with a heating value of about 13.0 MJ/m^3 (350 Btu/scf). High-Btu gasification further processes medium-Btu gas to produce a fuel gas with a heating value of approximately 37.0 MJ/m^3 (1000 Btu/scf).

---

[1] Higher heating value is defined as the heat content of the fuel plus the heat of vaporization of any water in the fuel.

Currently there are approximately 70 different gasifiers which have been or are under development. In addition, there are many different unit operations in each of these processes. The actual choice of a specific gasification system will depend on many factors including the coal properties, required gasifier size, etc. Therefore, the discussion presented here will focus on the choice between low-, medium-, and high-Btu gasification.

The major reactions which occur during coal gasification are:

$$C + \tfrac{1}{2}O_2 \rightarrow CO \qquad (4\text{-}1)$$

$$C + 2H_2 \rightarrow CH_4 \qquad (4\text{-}2)$$

$$C + H_2O \rightarrow CO + H_2 \qquad (4\text{-}3)$$

$$CO + H_2O \rightleftarrows CO_2 + H_2 \qquad (4\text{-}4)$$

$$CO + 3H_2 \rightleftarrows CH_4 + H_2O \qquad (4\text{-}5)$$

Carbon monoxide (CO) and hydrogen (H_2) are the major reaction products. Low-Btu gas contains approximately 20 percent CO and 15 percent H_2 with the balance composed principally of nitrogen (N_2). Medium-Btu gas contains approximately 50 percent CO and 40 percent H_2 with the balance mostly carbon dioxide (CO_2). High-Btu gas is produced by first processing medium-Btu gas in a shift conversion reactor where the following reaction occurs:

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (4\text{-}4)$$

The gas is then processed in a reactor where methane (CH_4) is produced by two reactions:

$$CO + 3H_2 \rightarrow CH_4 + H_2O \qquad (4\text{-}5)$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad (4\text{-}6)$$

Table 4-16 compares typical volumetric analyses for final product low-, medium-, and high-Btu gases to that of natural gas. As illustrated, the high-Btu gas is almost identical to natural gas while the composition of the low- and medium-Btu gases is very different.

As shown in Table 4-16, high Btu gas is nearly identical to natural gas. And it can be burned in existing gas/oil boilers with essentially no modifications. However, production of high Btu-gas requires additional equipment and results in a lower efficiency for the gasification process. Consequently, combustion of high-Btu gas in an industrial boiler is not economically attractive. Rather, low- or medium-Btu gas will be the choice for use as a boiler fuel.

TABLE 4-16. A COMPARISON OF COAL-BASED FUEL GAS COMPOSITIONS WITH THE COMPOSITION OF NATURAL GAS

Component (vol %-dry)	Low-Btu Gas[1]	Medium-Btu Gas[1]	High-Btu Gas[2]	Natural Gas[1]
CO_2	13.4	6.0	1.8	-
CO	15.1	55.9	-	-
H_2	22.4	37.4	4.2	-
CH_4	6.2	-	92.9	90.0
C_2H_6	-	-	-	5.0
N_2	42.9	0.7	1.1	5.0

[1] Source: BA-477
[2] Source: EL-052

Both low- and medium-Btu gas appear attractive for use in industrial boilers. Low-Btu gas is attractive because the gasification process is relatively simple. Low-Btu gasifiers can be operated at atmospheric pressure and they do not require an oxygen plant for operation. Medium-Btu gas is attractive because combustion of medium Btu gas produces approximately the same quantity of flue gas as combustion of natural gas. Therefore it can be burned in existing boilers more readily than low-Btu gas.

Boiler modification--Because the composition of low- and medium-Btu gas differs from that of natural gas, the coal-based fuels will burn differently in an existing gas/oil-fired unit. As a result, some boiler modifications will be required to permit combustion of coal-based gas in existing units. In addition, boiler derating may occur although in some cases, modification of the boiler will permit full capacity operation while firing coal-based gas.

The difficulty of converting an existing gas/oil-fired boiler to a coal-based fuel gas will increase as the heating value of the coal-based gas decreases. This is due to the fact that for a given firing rate, the volume and weight of both fuel and flue gas increases significantly as the fuel heating value goes down. Table 4-17 compares the relative volume and weight of fuel and flue gas for natural gas with that for low- and medium-Btu gas.

TABLE 4-17. RELATIVE VOLUME AND WEIGHT OF FUEL AND FLUE GAS FROM THE COMBUSTION OF LOW-BTU, MEDIUM-BTU, AND NATURAL GAS[1]

	Low-Btu Gas	Medium-Btu Gas	Natural Gas
Relative Volume			
Fuel	5.8	3.3	1.0
Combustion Air	0.7	0.8	1.0
Flue Gas	1.1	0.9	1.0
Relative Weight			
Fuel	6.0	2.8	1.0
Combustion Air	0.7	0.8	1.0
Flue Gas	1.1	0.9	1.0

[1] Details of combustion calculations are contained in Appendix B.

As shown, combustion of both low- and medium-Btu gas requires significantly higher fuel flow rates than natural gas. And fuel lines in existing boilers will not be capable of handling the increased flows. As a result, coal-based gas consumption will require modification of existing fuel supply headers and burners.

Combustion of low-Btu gas increases the volume and weight of flue gas by approximately 10 percent as compared to natural gas. This results in increased pressure drop in the boiler and some derating. In addition, the pattern of heat absorption in the boiler changes. This results in a loss of efficiency and in some cases can result in tube metal temperatures which exceed design temperatures.

Combustion of medium-Btu gas does not result in any significant changes in flue gas volume or weight. And only minor changes in the boiler heat absorption pattern occur. As a result, most existing boilers can burn medium-Btu gas with little or no modification to the boiler itself. Only changes in the fuel supply system and burners are required.

Table 4-18 presents the results of a study which was performed by Babcock and Wilcox (BA-477). This study examined the use of various grades of low- and medium-Btu gas in existing utility boilers. And although these boilers do differ somewhat from industrial units, the results of this study are applicable.

TABLE 4-18. ESTIMATED PERFORMANCE OF UNMODIFIED GAS AND OIL BOILERS FIRING DIFFERENT COAL-BASED FUEL GASES[1]

Fuel HHV		Gas Boiler		Oil Boiler	
(MJ/m^3)	(Btu/scf)	Efficiency (%)	Capacity (%)	Efficiency (%)	Capacity (%)
3.7	100	82	<50	81	<50
4.8	130	83	90	83	<50
6.3	170	82	95	82	<50
11.2	300	88	100	89	85
15.3	410	85	100	86	85
Original Design		85	100	90	100

[1] Source: BA-477

Table 4-18 shows boiler capacity and efficiency for gas- and oil-fired units which have been converted to coal-based gas firing. The only modification of the existing units was to the fuel supply and burners. As illustrated, medium-Btu gas can be fired in existing gas boilers with essentially no modification and no loss of efficiency or capacity. However, as the heating value of the gas declines below 11.2 MJ/m^3 (300 Btu scf), the boiler capacity and efficiency decline and the complexity of the modifications required to achieve full capacity increase. The combustion of coal-based gas in existing oil boilers results in some derating and loss of efficiency for all the coal-based gases studied. But as shown in Table 4-18, the trend of lower capacity and efficiency with lower heating value still holds.

In general, medium-Btu gas can be fired in existing boilers with little or no modification to the boiler itself. However, as the heating value of the gas declines, the required modifications become more extensive. Use of very low-Btu gas in existing gas/oil-fired boilers may result in such extensive modifications that coal-based gas firing is impractical.

Gas purification--Fuel gas from a gasifier contains a variety of compounds in addition to the major components identified in Table 4-16. These compounds include ash, tars, oils, H_2S, COS, CS_2, NH_3, cyanides, phenols, and thiocyanates. Direct combustion of raw gasifier gas in an industrial boiler could result in emission rates for particulates, sulfur dioxide, and nitrogen oxides which may require pollution control equipment to reduce emissions to acceptable levels. However, it is possible to clean coal-based gas prior to combustion and thus reduce or eliminate the requirement for emission controls.

Purification of raw gasifier gas is simpler than cleaning flue gases from a boiler for several reasons. First, purification of the fuel gas stream requires treatment of less than one-half the volume of gas which must be treated when flue gas cleaning is used. Second, commercially proven technology is available to remove reduced sulfur species from fuel gas. And finally, removal of sulfur compounds from fuel gas produces elemental sulfur which is easily handled and can be sold while many flue gas desulfurization systems produce a solid waste which must be disposed of in an environmentally acceptable manner.

Currently, there are many available gas purification processes and the choice of a particular system will depend on several factors. But some general statements can be made about the gas purification system which may be used. First, any gas purification system will remove essentially all the ash, tars, and oils present in the raw fuel gas. Second, nearly all the fuel bound nitrogen (e.g., NH_3) will be removed. And finally, the sulfur content of the product gas can be reduced to any specified level.

On-site vs. off-site gasification--Gasification is not being extensively used to supply boilers with fuel at this time. The primary reason for this is that natural gas and oil are significantly less expensive than the fuel gas which could be produced by a gasifier. This is especially true for small (less than 75 MW equivalent - 250 x 10^6 Btu/hr) units. Only for very large (over 1200 MW equivalent - 4000 x 10^6 Btu/hr) gasification facilities does the benefit of scale begin to level fuel gas costs. Because of this, current projections indicate that most coal-based gas which will be used as a fuel in existing boilers will be produced at a large central gasification facility (OL-065). These facilities will not become available until an economic incentive exists to produce medium-Btu gas.

4.3.4.2 Costs--

There are two costs associated with the use of gasification as a fuel switching method. The first is the cost of the gasifier and associated process equipment such as a gas purification system. In the case of a small boiler, this cost would be reflected in the cost of fuel gas purchased from a central gasification facility. These costs are not addressed in this section. They will be developed as part of an ITAR which is being prepared for synthetic fuels.

The second cost associated with a gas/oil to coal-gas fuel switch is the cost of modifications required to permit firing of coal gas in an existing boiler. This also includes costs due to a change in boiler operating and maintenance costs which results when a boiler switches to coal-gas. These costs are examined in the following discussion.

Capital costs--The capital costs of the modifications required to permit firing of low- or medium-Btu gas in a gas/oil-fired boiler will depend on the extent of the modifications. If the modifications include only required changes in the fuel supply system and the burners, one cost will be incurred. But, if the modifications include changes in the boiler required to offset derating which may result from switching fuels, a higher cost will be incurred.

Figure 4-19 presents estimated costs required to modify the fuel supply system and burner to permit firing of low- and medium-Btu gas in an existing oil boiler. No estimates of modification costs have been prepared for a gas to coal-gas conversion but these costs can be approximated by the costs of an oil to coal-gas conversion. As shown in Figure 4-19, the costs of converting to low-Btu gas firing are approximately 25 percent higher than the costs of converting to medium-Btu gas firing. This is due to the fact that low-Btu gas will require larger fuel supply lines, and the installation of burners will be more difficult.

The costs of modifying an existing boiler to fire low- and medium-Btu gas at full capacity have not been estimated for industrial size boilers. But, these costs have been estimated for utility boilers. They can be applied to industrial boilers by assuming that the relative change in cost as a function of gas heating value is the same for both utility and industrial boilers. Based on this assumption, the cost of modifying an oil boiler to fire low-Btu gas (5 MJ/m^3 - 130 Btu/scf) at full capacity is over sixteen times the cost of modifications required to fire medium-Btu gas (11.2 MJ/m^3 - 300 Btu/scf) at full capacity. And the cost of modifying an existing gas boiler to fire low-Btu gas at full capacity is over four times the cost of modifications required to fire medium-Btu gas at full capacity (BA-477).

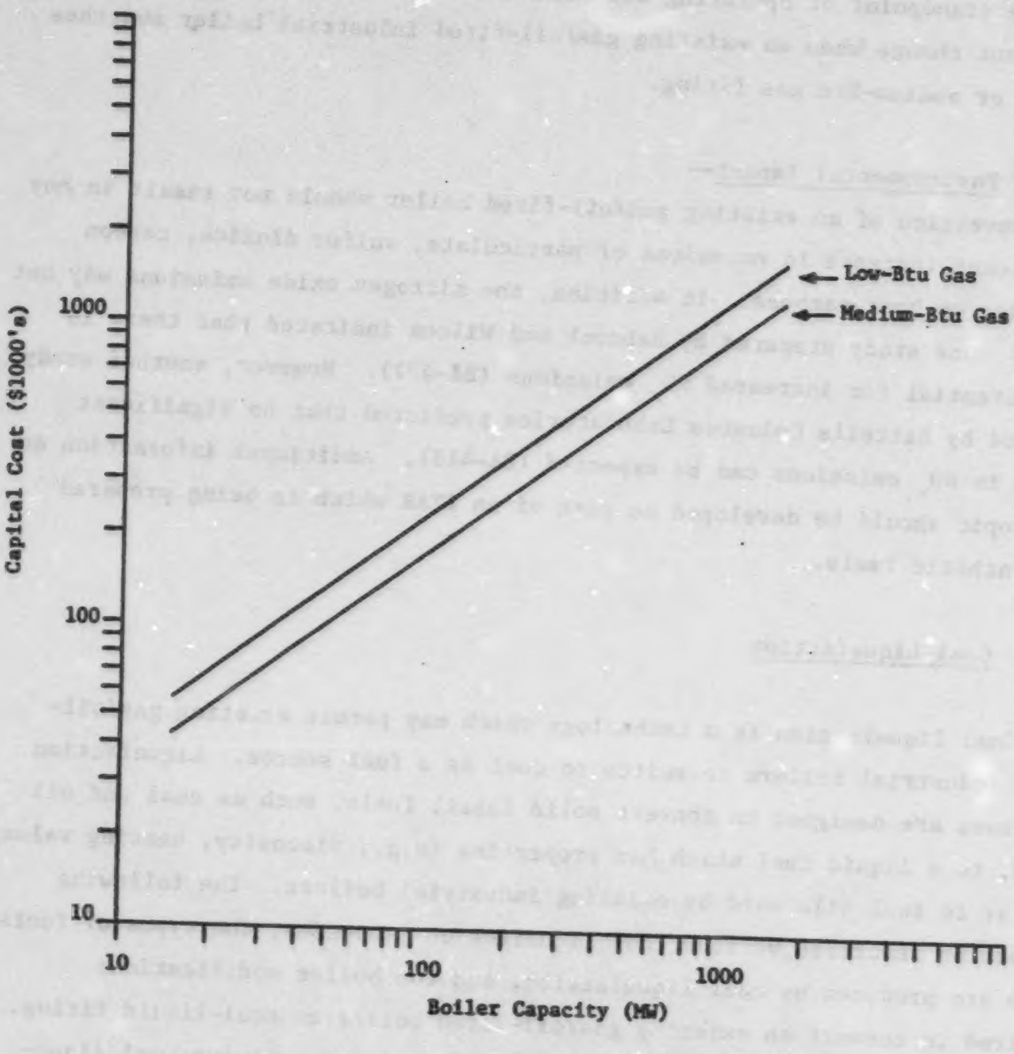


Figure 4-19. Estimated capital costs of modification to boiler fuel supply system and burners (1978$).

Source: SC-273

Operating and maintenance costs--Combustion of low- or medium-Btu gas in an existing boiler is essentially identical to combustion of natural gas from the standpoint of operating and maintenance costs. Therefore, O&M costs should not change when an existing gas/oil-fired industrial boiler switches to low- or medium-Btu gas firing.

4.3.4.3 Environmental Impact--

Conversion of an existing gas/oil-fired boiler should not result in any significant increase in emissions of particulate, sulfur dioxide, carbon monoxide, or hydrocarbons. In addition, the nitrogen oxide emissions may not change. One study prepared by Babcock and Wilcox indicated that there is some potential for increased NO_x emissions (BA-477). However, another study prepared by Battelle Columbus Laboratories predicted that no significant change in NO_x emissions can be expected (BA-448). Additional information on this topic should be developed as part of an ITAR which is being prepared for synthetic fuels.

4.3.5 Coal Liquefaction

Coal liquefaction is a technology which may permit existing gas/oil-fired industrial boilers to switch to coal as a fuel source. Liquefaction processes are designed to convert solid fossil fuels, such as coal and oil shale, to a liquid fuel which has properties (e.g., viscosity, heating value) similar to fuel oils used by existing industrial boilers. The following discussion describes various coal liquefaction processes, the types of fuels which are produced by coal liquefaction, and the boiler modifications required to convert an existing gas/oil-fired boiler to coal-liquid firing. In addition, estimates are presented for the costs of applying coal liquefaction to industrial boilers and for the change in pollutant emissions which may result when coal-liquids are fired in an existing gas/oil boiler.

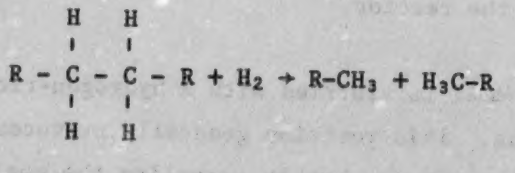
4.3.5.1 Coal Liquifaction - Process Description--

The liquefaction of coal and subsequent combustion of the liquid fuel in an existing boiler is a technically feasible method of switching from gas or oil to a coal-derived fuel. Currently, processes which produce coal-liquids are not sufficiently developed to even marginally contribute to the fuel demands of industrial boilers, but the potential for coal liquefaction processes to provide a substantial share of the future U.S. energy demands is evident. There are many factors which must be examined when considering coal liquefaction as a method of switching fuels. Some of the more important factors are:

1) Type of liquefaction process employed
2) Boiler modifications required to fire coal-liquids
3) Coal-liquid purification requirements
4) On-site versus off-site liquefaction
5) Costs associated with liquefaction
6) Pollution control required for a converted boiler

The following discussion examines the first four of these factors in Costs are discussed in Section 4.3.5.2 and pollution control is discussed in Section 4.3.5.3.

Type of liquefaction process--The basic reaction of coal liquefaction is similar to thermal cracking in the petroleum refining industry. The addition of molecular hydrogen (H_2) across a carbon-carbon bond causes separation of the large carbon chains found in coal into smaller chains as shown in equation 4-7;



$$R - \underset{H}{\overset{H}{\underset{|}{\overset{|}{C}}}} - \underset{H}{\overset{H}{\underset{|}{\overset{|}{C}}}} - R + H_2 \rightarrow R\text{-}CH_3 + H_3C\text{-}R \tag{4-7}$$

where R is a hydrocarbon structure such as ($-CH_3$), ($-CH_2CH_3$), ($-CH_2CH_2CH_3$), etc.

In coal, the (R) groups are generally composed of complex aromatic hydrocarbons.

When coal is formed, gases diffuse out of it, leaving voids and fissures. Liquefaction processes introduce solvent into these voids, causing the coal to dissolve. Hydrogen can then be added to the dissolved coal to form relatively low molecular weight compounds. If hydrogen is not added, the coal will polymerize into asphaltenes.

The ability to provide hydrogen for reaction with dissolved coal by increasing mass transfer is very important. In fact, the major difference between various coal liquefaction processes is the method of hydrogen transfer.

There are three types of coal liquefaction processes. They are:

1) hydrogenation,
2) carbonization, and
3) gasification/coal-liquid synthesis (Fischer-Tropsch Synthesis)

Hydrogenation is gaining prominence over the other systems because it is in an advanced stage of development, provides more flexible utilization of product fuel, has a higher overall conversion efficiency, and shows better market potential and economic advantages. Hydrogenation involves the direct conversion of coal to liquids by addition of hydrogen to coal at elevated temperature and pressure. Three types of hydrogenation are typified by the method of hydrogen transfer used in the reactor.

In noncatalytic hydrogenation, coal is slurried with a hydrogen-rich solvent and reacted with hydrogen gas. This reaction generally produces a liquid that solidifies at ambient temperature, but by recycling the coal-solvent slurry, additional hydrogenation occurs and a less viscous product can be obtained. The Solvent Refined Coal (SRC) process uses this method.

SRC-I fuel is a solid having lower sulfur and ash content than the base coal, but SRC-I is only suited as an alternate fuel for coal-fired boilers and cannot be used in existing gas/oil-fired units. SRC-II fuel is produced by recycling coal-solvent slurry. This is a coal-liquid which possesses properties similar to residual fuel oil.

In catalytic hydrogenation, pulverized coal is slurried with coal-derived oil, mixed with hydrogen, and fed to a reactor which utilizes a hydrodesulfurization (cobalt-molybdenum) catalyst to increase the rate of hydrogen transfer. This method is employed by the H-Coal process.

In solvent hydrogenation, no hydrogen gas or catalyst is used in the reactor. Instead, a solvent is used to provide hydrogen to the free radicals as they break away from the coal polymer. This solvent, known as a "donor", is composed of organic compounds which boil between 200-480°C (400-900°F) and which must be regenerated after they are depleted of hydrogen. The Exxon Donor Solvent (EDS) process employs this method of hydrogenation.

In the carbonization system, coal is converted to liquid by application of heat, either without the direct addition of hydrogen (pyrolysis), or with the addition of hydrogen (hydrocarbonization). Most of the carbon is rejected as a solid, but liquid products are recovered which have a higher hydrogen/carbon ratio than the original coal. This process does not have a high conversion efficiency of coal to liquid fuel. Therefore, it is not well suited to producing an industrial boiler fuel.

The liquefaction process which uses gasification followed by coal-liquid synthesis is very complex, and the costs of producing liquid fuel by this process are not competitive with other liquefaction systems. Therefore, this system is not a feasible method of switching from gas/oil to a coal-based fuel.

Boiler modifications--The extent of the modifications required for combustion of coal-liquids in gas/oil-fired industrial boilers will depend on the composition and physical properties of the coal-derived liquid fuel to be used. An existing boiler can burn a coal-liquid fuel which resembles distillate or residual oil with some modifications, but if the fuel is markedly different from distillate or residual oil, significant changes in the boiler may be required.

A comparison of physical and chemical characteristics of representative distillate and residual fuel oils and coal-liquids is presented in Table 4-19. The distillate and residual fuel oils are No. 2 and No. 6, respectively. Coal-liquids in the table are SRC-II, H-Coal distillate, and EDS distillate. In comparison, all of the coal-liquids exhibit lower hydrogen content than either of the fuel oils. Also, sulfur and nitrogen contents in these coal-liquids are considerably higher than No. 2 fuel oil. The coal-liquids heat of combustion is not significantly different from that of the fuel oils.

To date, there are only limited data on storage and combustion of liquids from any liquefaction processes. The only facility in the United States currently conducting tests on coal-liquids is the 22 MW Plant Mitchell power station of the Georgia Power Company. Only limited tests on industrial boilers have been performed with SRC-II, H-Coal, and EDS liquid fuels. More extensive boiler tests are being planned for SRC-II in August, 1978. Tests on H-Coal and EDS fuel products will be initiated in 1979 and 1980, respectively.

Due to the lack of data on the combustion of coal-liquids in industrial boilers, a complete estimation of the boiler modifications required to fire gas/oil boilers with coal-liquids cannot be made. However, an estimate of these modifications can be made based on the physical and chemical characteristics of the coal-liquids.

Because the composition of coal-derived liquid fuels differs from that of distillate and residual fuel oils, the coal-derived fuels will burn differently in existing gas/oil-fired units. As a result, some boiler modifications will be required in order to permit combustion of coal-liquids in existing industrial boilers. In some cases, boiler derating may occur, but

TABLE 4-19. PROPERTIES OF TYPICAL DISTILLATE AND RESIDUAL FUEL OILS AND COAL-LIQUIDS[1]

Fuel	Petroleum No. 2 (distillate)	Petroleum No. 6 (residual)	SRC-II	H-Coal	EDS
Elemental composition, wt%					
Hydrogen	12.9	10.7	7.4	9.1	10.0
Sulfur	0.5	3.0	0.37	0.10	0.3
Nitrogen	0.008	0.23	0.62	0.39	0.2
Oxygen	<0.01	0.5	3.9	1.5	1.9
Trace contaminants, ppm wt					
Titanium	<1.0	DNA[2]	20.0	0.59	DNA
Sodium	0.55	DNA	0.39	0.08	DNA
Potassium	0.37	DNA	0.19	0.14	DNA
Calcium	0.17	DNA	0.35	0.1	DNA
Vanadium	<0.1	DNA	0.9	<1.0	DNA
Lead	-	DNA	0.9	10.3	DNA
Iron	0.2	DNA	61.0	-	DNA
Chloride	-	DNA	35.0	-	DNA
Gravity, °API	33.6	14.0	5.3	14.7	18.0
Aromatic carbon, %	19.0	DNA	74.0	55.0	-
Flash point, C	67.2	DNA	82.2	90.5	91.1
Heat of combustion, MJ/kg	45.4	42.8	39.4	42.1	44.2

[1] Source: HI-220

[2] DNA - Data not available

with the implementation of appropriate modifications, maximum capacity can probably be maintained.

The conversion of an existing gas-fired boiler to coal-liquids firing will not be significantly different from converting a gas-fired unit to residual fuel oil. The important factors to consider are:

1) Furnace size - Coal-liquids will have a higher furnace heat release rate than natural gas. Therefore, more heat will be absorbed in an oil-fired boiler's furnace than a gas-fired furnace. Derating will be necessary to maintain a safe heat release rate.

2) Coal-liquid storage - The space required for a minimum of 10 day fuel storage may present a problem at some industrial locations.

3) Coal-liquid firing equipment - Fuel supply lines and burners will have to be replaced to accomodate coal-liquid instead of gas.

4) Boiler internal modification - Because of higher heat release rates and the presence of ash, addition of heat transfer surface to the superheater or reheater may be required. The removal of heating surface from the furnace may also be required. Soot blowers may be required to periodically remove any ash deposits. Other items which may need checking or modification are fans, economizers, and air preheaters.

5) Pollution control - The exact impact of residual-type coal-liquids will depend on the fuel properties. Particulate and sulfur dioxide emissions are most likely to be affected by a switch from natural gas to coal-liquid fuels.

A more detailed analysis of switching from a gas to liquid fuel can be found in Section 4.2.1.

The conversion of an existing oil-fired boiler (distillate or residual) to coal-liquids firing will require a minimum of modifications. Only factors which are affected by the change of physical or chemical characteristics in the oil feedstock are of real concern. The primary items to consider are higher viscosities which can increase the pressure drop in fuel supply lines and reduce fuel flow, and increased pollutant emissions which may result from higher ash and sulfur in the coal-liquids.

Coal-liquid purification--Any compound which is in the coal feedstock to a liquefaction facility may be present in the coal-liquids produced. In the process of conversion to coal-liquids, a number of organic or inorganic compounds making up the coal polymer may be transformed into an unwanted or potentially hazardous substance. Purification of the coal-liquids to remove unwanted and potentially toxic compounds has been limited principally to filtration, hydrodesulfurization, and vacuum distillation. These operations have been able to substantially reduce the presence of particulates, sulfur compounds, fuel-bound nitrogen, and hazardous hydrocarbons from ths final coal-liquid product.

On-site versus off-site liquefaction--Another factor which must be seriously considered before any gas/oil-fired industrial boiler switches to coal-derived liquids as its principal source of fuel is whether the coal-liquids should be produced on-site or purchased from an off-site supplier. The predominant criteria for selecting the appropriate route for any specific industry is the economic impact realized through on-site or off-site application to existing or future facilities.

On-site production of coal-liquids for use by industrial boilers seems to be limited to a small number of applications. Only industries where the demand for large, continuous supplies of liquid fuel are high would be able to realize the economies of scale associated with a coal liquefaction facility. Any industry that requires only small amounts of fuel would not find the installation of a coal liquefaction plant to their advantage. In these smaller applications, off-site production and purchase from a central supplier would be the appropriate choice.

4.3.5.2 Costs of Liquefaction--

There are two major costs associated with the installation of a coal liquefaction facility. The first of these is the cost of purchasing and installing the principal equipment necessary to transform the solid coal to a useable coal-liquid. This cost may be realized directly by those industries who choose to produce coal-liquids onsite and indirectly by those industries who choose to purchase coal-liquids from a central supplier. The second cost is that associated with the conversion of an existing gas/oil-fired boiler to coal-liquids firing. These costs will be reflected in modifications made to the existing boiler system and changes in boiler operating and maintenance costs which result when a gas/oil boiler switches to coal-liquids.

Capital costs--Insufficient data are available at this time to estimate the initial capital costs incurred when installing a coal liquefaction facility. These costs will not be addressed in this section. They will be developed as part of an ITAR which is being prepared for synthetic fuels.

Very limited data are available on the costs of modifications required to permit firing of coal liquids in an existing industrial boiler. Figure 4-20 presents the cost modification versus boiler capacity for switching an oil-fired boiler to SRC-II fuel. Data on the costs incurred for switching to H-Coal or EDS fuels are not available, but may be considered similar to those for SRC-II.

No reliable estimates for the costs of switching from gas to coal-liquids exist. The most reasonable approach to estimating such costs would be to assume that these costs would be similar to those required for switching from gas to residual fuel oil. These costs have been presented in Figures 4-3 and 4-4.

Operating and maintenance costs--Combustion of a coal-liquid fuel in an existing boiler is essentially identical to combustion of residual fuel oil from the standpoint of operating and maintenance. Therefore, O&M costs should not change significantly when an existing gas/oil-fired boiler switches to firing coal-liquid fuel.

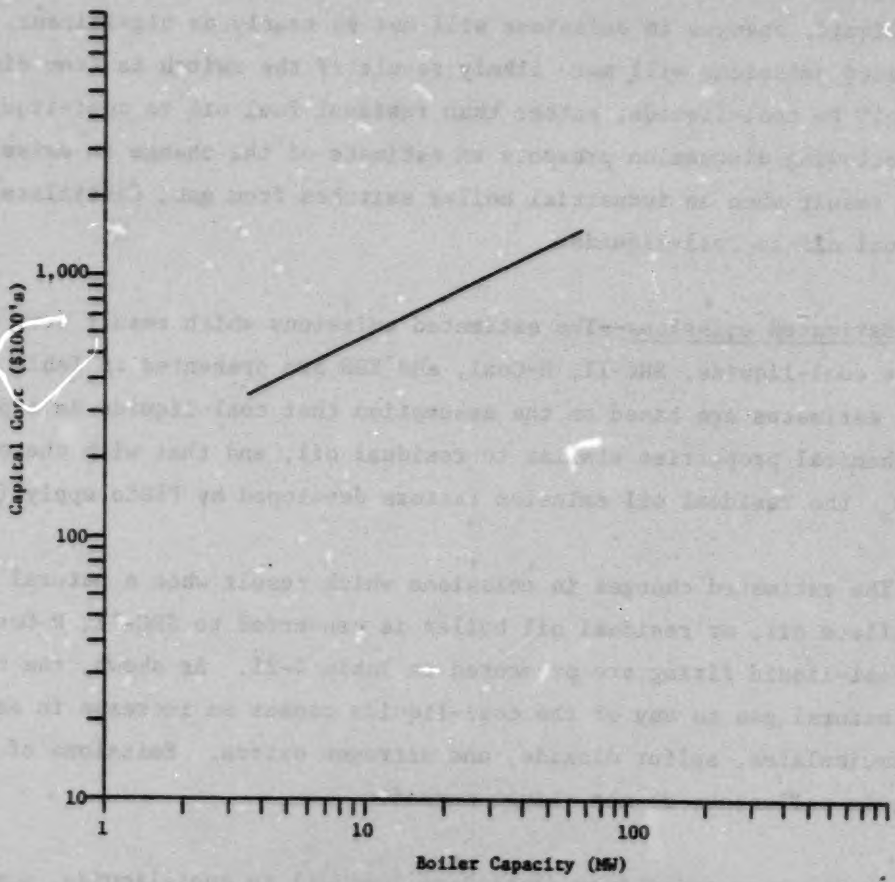


Figure 4-20. Estimated capital costs for modification of an oil boiler to fire SRC-II ($1978).
Source: SC-273

4.3.5.3 Environmental Impact--

Conversion of an existing gas/oil-fired boiler to coal-liquids firing may result in an increase in emissions. If the conversion is from gas to coal-liquids, significant increases in emissions of particulates, sulfur dioxide, and nitrogen oxides may occur. If the conversion is from oil to coal-liquid, changes in emissions will not be nearly as significant. Increased emissions will more likely result if the switch is from distillate fuel oil to coal-liquids, rather than residual fuel oil to coal-liquids. The following discussion presents an estimate of the change in emissions which result when an industrial boiler switches from gas, distillate oil, or residual oil to coal-liquids.

Estimated emissions--The estimated emissions which result from combustion of the coal-liquids, SRC-II, H-Coal, and EDS are presented in Table 4-20. These estimates are based on the assumption that coal-liquids have physical and chemical properties similar to residual oil, and that with the exception of NO_x, the residual oil emission factors developed by PEDCo apply (PE-348).

The estimated changes in emissions which result when a natural gas, distillate oil, or residual oil boiler is converted to SRC-II, H-Coal, or EDS coal-liquid firing are presented in Table 4-21. As shown, the conversion from natural gas to any of the coal-liquids causes an increase in emissions of particulates, sulfur dioxide, and nitrogen oxides. Emissions of other criteria pollutants do not change markedly.

In the conversion from distillate fuel oil to coal-liquids, some decrease in sulfur dioxide emissions may occur. Slight decreases in carbon monoxide and hydrocarbons would also be predicted.

If coal-liquids replace residual fuel oil in boilers, no significant change in emissions would be noted for particulates, carbon monoxide, or hydrocarbons, but substantial reductions of sulfur dioxide and nitrogen oxide emissions would occur.

TABLE 4-20. ESTIMATED EMISSIONS USING SRC-II, H-COAL, AND EDS COAL-LIQUIDS IN INDUSTRIAL BOILERS

Pollutant	SRC-II		H-Coal		EDS	
	(ng/J)	(lb/10^6 Btu)	(ng/J)	(lb/10^6 Btu)	(ng/J)	(lb/10^6 Btu)
Particulates[1]	40.4	9.4×10^{-2}	37.8	8.8×10^{-2}	36.0	8.4×10^{-2}
Sulfur dioxide[1]	181.0	0.4	46.0	0.1	131.0	0.3
Nitrogen oxides[2] as NO_2	110-226	0.3-0.5	110-226	0.3-0.5	110-226	0.3-0.5
Carbon monoxide[1]	15.0	3.5×10^{-2}	14.0	3.3×10^{-2}	13.4	3.1×10^{-2}
Hydrocarbons[1] as CH_4	2.3	5.3×10^{-3}	2.1	4.9×10^{-3}	2.0	4.7×10^{-3}

[1] Source: PE-348

[2] Source: HI-220

TABLE 4-21. ESTIMATED CHANGE IN EMISSIONS WHICH RESULTS WHEN GAS/OIL-FIRED BOILERS SWITCH TO COAL-LIQUIDS

	Change in Emission Rate (ng/J)								
	Natural Gas to			Distillate Fuel Oil to			Residual Fuel Oil to		
Pollutant	SRC-II	H-Coal	EDS	SRC-II	H-Coal	EDS	SRC-II	H-Coal	EDS
Particulates[1]	39.0	36.4	34.6	31.4	28.8	27.0	1.7	(0.9)	(2.7)
Sulfur dioxide[1]	80.7	45.7	130.7	(34.0)	(169.0)	(84.0)	(1281.2)	(1332.2)	(1247.2)
Nitrogen oxide[2] as NO_2	110-226	110-226	110-226	24-140	24-140	24-140	(23-93)	(23-93)	(23-93)
Carbon monoxide[1]	7.7	6.7	6.1	(0.5)	(1.5)	(2.1)	(0.5)	(1.5)	(2.1)
Hydrocarbons[1] as CH_4	1.0	0.8	0.7	(0.8)	(1.0)	(1.1)	(0.8)	(1.0)	(1.1)

	Change in Emission Rate ($lb/10^6$ Btu)								
	Natural Gas to			Distillate Fuel Oil to			Residual Fuel Oil to		
Pollutant	SRC-II	H-Coal	EDS	SRC-II	H-Coal	EDS	SRC-II	H-Coal	EDS
Particulates[1]	9.0×10^{-2}	8.5×10^{-2}	8.0×10^{-2}	7.3×10^{-2}	6.7×10^{-2}	6.3×10^{-2}	0.4×10^{-2}	(0.2×10^{-2})	(0.6×10^{-2})
Sulfur dioxide[1]	0.2	0.1	0.3	(0.08)	(0.4)	(0.2)	(3.0)	(3.1)	(2.9)
Nitrogen oxide[2] as NO_2	0.25 - 0.5	0.25 - 0.5	0.25 - 0.5	0.06 - 0.33	0.06 - 0.33	0.06 - 0.33	(0.05-0.21)	(0.05-0.21)	(0.05-0.21)
Carbon monoxide[1]	1.8×10^{-2}	1.6×10^{-2}	1.4×10^{-2}	(0.1×10^{-2})	(0.3×10^{-2})	(0.5×10^{-2})	(0.1×10^{-2})	(0.3×10^{-2})	0.5×10^{-2}
Hydrocarbons[1] as CH_4	2.3×10^{-3}	1.9×10^{-3}	1.6×10^{-3}	(1.9×10^{-3})	(2.3×10^{-3})	(2.6×10^{-3})	(1.9×10^{-3})	(2.3×10^{-3})	2.6×10^{-3}

[1] Source: PE-348

[2] Source: HI- 220

Pollution control equipment--Based on the estimates presented in Table 4-21, it appears that the emissions which will result from the combustion of coal-liquid fuels may require some control. Although particulate and sulfur dioxide emission rates are below current utility boiler NSPS, nitrogen oxide emission rates may not be, but combustion modifications should be capable of reducing NO_x emissions to acceptable levels.

SECTION 5

FACTORS AFFECTING FUEL SWITCHING

Six methods for switching fuels in existing industrial boilers were identified in Section 4. They are:

1) gas to oil, boiler modification
2) gas/oil to coal, boiler replacement
3) gas/oil to coal, boiler modification
4) gas/oil to coal-oil mixture firing
5) gas/oil to coal-based gas firing
6) gas/oil to coal-based liquid firing

The first of these methods is for switching from gas to oil. The remaining five are for switching from gas/oil to coal or a coal-based fuel. While all of these fuel switching methods are technically feasible, some are more economically attractive than others. In order to determine which fuel switching methods are more likely to be employed by existing industrial boilers, the costs of switching by each method and the regulations which apply to fuel switching must be compared.

This section presents a discussion of the relative costs, applicable regulations, and the environmental impacts associated with each fuel switching method. The costs and other factors are determined for each fuel switching method applied to three standard boilers. These standard boilers were developed by PEDCo Environmental Specialists, Inc. as background for NSPS which are being prepared for industrial boilers.

The costs presented in this section include fuel costs and the estimated capital costs of any modifications required to switch fuels. Costs are presented for three cases. In the first case, the only capital costs which are included are the costs for boiler conversion. The second case includes capital costs associated with pollution control in addition to the capital costs of boiler conversion. And the third case presents costs based on provisions of the National Energy Plan. The regulations considered in this section include the current fuel switching mandate defined in the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (as amended) and the impact of applicable provisions of the National Energy Plan (NEP). The environmental impacts which are presented include an estimate of the uncontrolled emissions of criteria pollutants from three standard boilers for each applicable fuel switching method.

5.1 STANDARD BOILERS

In order to assess the costs and environmental impact of the fuel switching methods defined in this report, specific boiler configurations must be examined. These specific boiler configurations, referred to as "standard boilers", are representative of boilers which comprise the existing industrial boiler population. The standard boilers which are presented and examined in this section were developed by PEDCo Environmental Specialists, Inc. as the result of a characterization of the U.S. industrial boiler population by fuel, firing mechanism, type, and capacity.

The use of standard boilers will facilitate the assessment of fuel switching in industrial boilers. This is because fuel switching in a standard boiler is easily defined while fuel switching in industrial boilers as a class is more general and less well defined. Specifics of costs, emissions, and regulatory impact can be quantified for standard boilers. And because the standard boilers are representative of the industrial boiler population, the results of an assessment using standard boilers are widely applicable.

Seven standard boilers have been identified as part of the study to develop background information in support of industrial boilers NSPS. Characteristics of these boilers are presented in Table 5-1. As shown, four of the seven standard boilers are coal-fired. Therefore, only the following three standard boilers are candidates for fuel switching by the methods considered in this study:

1) Gas-fired, fire tube boiler
2) Distillate oil-fired, fire tube boiler
3) Residual oil-fired, water tube boiler

Design parameters for these boilers are presented in Table 5-2. The parameters include capacity, fuel characteristics, load factor, and flue gas characteristics.

TABLE 5-1. STANDARD BOILER CHARACTERISTICS[1]

Boiler Configuration	Boiler Capacity MW	Boiler Capacity (10^6 Btu/hr)	Fuel
Package, fire tube, scotch	4.4	15	Natural Gas
Package, fire tube, scotch	4.4	15	Distillate Oil
Package, water tube, underfeed stoker	8.8	30	Coal
Package, water tube, chaingrate stoker	22	75	Coal
Package, water tube	44	150	Residual Oil
Field erected, water tube, spreader, stoker	44	150	Coal
Field erected, water tube, pulverized coal	58.6	200	Coal

[1] Source: PE-348.

The following sections will examine fuel switching in each of the three standard boilers. Costs will be determined based specifically on the capacities and load factors presented in Table 5-2. In addition, the impact of fuel switching on the standard boiler design parameters will be estimated.

5.2 IMPACT OF ESECA AND THE NEP ON FUEL SWITCHING

The embargo on petroleum during the winter of 1973-74 made clear that continued dependence on oil and natural gas was leading the nation (and the world) toward a severe energy crisis. The 1973-74 embargo resulted in long gasoline lines, reduced speed limits, increased energy prices, and a growing awareness of the limits of domestic energy sources, particularly domestic supplies of oil and natural gas.

One Congressional response to the energy crisis was the passage of the Energy Supply and Environmental Coordination Act of 1974 (ESECA), as amended by the Energy Policy and Conservation Act of 1975 (EPCA). This act was designed to increase the use of coal in industrial and utility boilers, thereby decreasing U.S. dependence on natural gas and foreign oil.

Under the provisions of ESECA (as amended) the administrator of the Federal Energy Administration (FEA) was authorized to prohibit power plants and major fuel burning installations (MFBI's)[1] from burning natural gas or petroleum products as their primary energy source and to require that power plants and MFBI's in the early planning process be designed and constructed to be capable of burning coal as their primary energy source. Currently, the Economic Regulatory Administration of the Department of Energy (DOE) has the authority originally granted to the administration of the FEA and this authority expires on December 31, 1978 (SC-538).

---

[1] A major fuel burning installation is defined as a single combustion source having a capacity above 30 MW (100×10^6 Btu/hr) or a group of combustion sources at a single site with a combined capacity over 75 MW (250×10^6 Btu/hr).

TABLE 5-2. DESIGN PARAMETERS FOR STANDARD BOILERS SUBJECT TO FUEL SWITCHING[1]

Design Parameter	Natural Gas Fired, Fire Tube Boiler		Distillate Oil Fired, Fire Tube Boiler		Residual Oil Fired, Water Tube Boiler	
Capacity						
(MW)	4.4		4.4		4.4	
(10^6 Btu/hr)	15		15		150	
Fuel Analysis						
% Sulfur	Trace		0.5		3.0	
% Ash	Trace		Trace		0.1	
HHV	37.3 (MJ/m^3) 1000 (Btu/ft^3)		38.8 (MJ/ℓ) 139,000 (Btu/gal)		41.8 (MJ/ℓ) 149,800 (Btu/gal)	
Excess Air (%)	15		15		15	
Flue Gas Flow Rate						
(Nm^3/hr)	5370		5160		45400	
(acfm)	5200		5000		46700	
Flue Gas Temperature						
(°C)	177		177		204	
(°F)	350		350		400	
Load Factor (%)	45		45		55	
Emission Rate	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)
particulates	0.02	0.05	0.14	0.315	0 6.1	13.5
sulfur dioxide	0.005	0.01	3.34	7.35	213.8	470.4
nitrogen oxides as NO_2	0.68	1.50	1.36	3.00	21.1	46.5
carbon monoxide	0.12	0.26	0.25	0.54	2.3	5.0
hydrocarbons as CH_4	0.02	0.05	0.05	0.11	0.5	1.0

---

[1] Source: PE-348

Before existing power plants or MFBI's can be prohibited from burning petroleum products on natural gas, the following conditions must be met (FE-260).

1) The power plant or MFBI had on June 22, 1974, or thereafter acquired or was designed with the necessary plant equipment and capability to burn coal, or has been required to meet a design and construction requirement under ESECA.
2) Issuance of a prohibition order is practicable and consistent with the purposes of ESECA.
3) Coal and coal transportation facilities will be available during the period the prohibition order will be in effect.
4) For power plants, the prohibition order will not impair the reliability of service in the area served by the power plant.

In selecting major fuel burning installations for receipt of a prohibition order, DOE must consider, among other factors, the location of the installation, the production or output of the installation, the purpose for which coal would be burned, the quantity of natural gas or petroleum products presently burned, and the practicability of burning coal given the short-term variation of demand for output by the installation.

DOE is required by ESECA to issue prohibition orders to power plants for which it makes the above findings, but its authority to issue prohibition orders to qualified MFBI's is discretionary (FE-260).

At present, the authority granted DOE under ESECA has limited MFBI prohibition orders. Only industrial boilers larger than 30 MW (100 x 10^6 Btu/hr) which were originally designed to fire coal are being ordered to convert to coal (DE-339). Therefore, the provisions of ESECA will only impact one of the three standard boilers which are candidates for fuel switching. This is the residual fuel oil-fired boiler which has a capacity of 44 MW (150 x 10^6 Btu/hr). However, only a fraction of the industrial boilers represented by the residual oil-fired standard boiler were originally designed to fire coal.

A survey of MFBI's was conducted by FEA in the spring of 1975. This survey was designed to determine the number of industrial boilers firing oil and gas which were originally designed to fire coal. Currently, only cumulative results of this survey are available. A total of 1242 gas/oil fired MFBI's was identified which had previously burned coal or were built with coal burning capability (FE-260). The inventory of the U.S. industrial boiler population prepared by PEDCo indicates that there are a total of 4251 existing gas/oil fired boilers with capacities above 30 MW (100 x 10^6 Btu/hr)(PE-346). In addition, 1281 non-boiler gas/oil fired MFBI's were identified (BR-508). Therefore, approximately 22 percent of all gas/oil fired MFBI's have or had coal burning capability. Assuming that this percentage is equal for boilers and non-boilers, approximately 22 percent of the industrial boilers represented by the residual oil fired standard boiler may be required to switch to coal-firing under the provisions of ESECA. The gas- and distillate oil-fired standard boilers are not required to switch to coal under ESECA.

There are two facets of the National Energy Plan which impact fuel switching in existing industrial boilers. The first is a regulatory program which has provisions similar to ESECA. The major provisions of this program are:

1) A prohibition on the use of natural gas or oil in new industrial boilers with capacities above 30 MW (100 x 10^6 Btu/hr) and in all new power plants.
2) Authority to prohibit existing MFBI's which have the capability to burn coal from burning gas or oil on a case-by-case basis, or in categories.

3) Authority to prohibit categories of new non-boilers with capacities greater than 30 MW (100 x 10^6 Btu/hr) from burning gas or oil.

4) A prohibition on the use of natural gas in any power plant after 1990.

5) Discretionary authority to prohibit use of gas or oil in existing MFBI's and power plants in categories or on a case-by-case basis.

6) Authority to limit the use of gas or oil in combination with coal in existing MFBI's and power plants on a case-by-case basis.

7) Exemptions for economic, environmental, fuel availability, and technical reasons.

The impact of the regulatory portion of the NEP on fuel switching in existing boilers is identical to the impact of ESECA. One of the primary differences between the regulatory program and ESECA is that the burden of proof in determining if an existing boiler can feasibly fire coal is no longer DOE's responsibility. Under the NEP, the boiler operator must prove that coal cannot be fired before an exemption will be granted (SC-538) (US-768).

The second facet of the NEP which impacts fuel switching is a fuel tax/investment credit program. This program provides for a fuel tax on natural gas and oil and a credit for investment in coal firing equipment. The maximum annual investment credit is limited to the annual fuel tax incurred. However, the investment credit can be carried over from year to year and applied to any fuel tax incurred in the future.

The following discussion of the fuel tax/investment credit program is based on a report prepared by the Executive Office of the President and released in June, 1977 (US-768).

TABLE 5-3. ESTIMATED FUEL COSTS THROUGH 1990 WITH AND WITHOUT PROPOSED NEP FUEL TAXES

Fuel Type	Fuel Cost									
	1978[1]		1985[1]		1985 with Tax[2]		1990[1]		1990 with Tax[2]	
	\$/GJ	\$/10^{6} Btu	\$/GJ	\$/10^{6} Btu	\$/GJ	\$/10^{6} Btu	\$/GJ	\$/10^{6} Btu	\$/GJ	\$/10^{6} Btu
High-Sulfur Coal	0.70	0.74	1.13	1.19	NA	NA	1.58	1.67	NA	NA
Low-Sulfur Eastern Coal	1.10	1.16	1.76	1.86	NA	NA	2.47	2.61	NA	NA
Low-Sulfur Western Coal	0.40	0.42	0.64	0.67	NA	NA	0.89	0.94	NA	NA
Residual Oil	2.09	2.21	3.36	3.55	4.29	4.53	4.72	4.98	6.03	6.36
Distillate Oil	2.84	3.00	4.57	4.82	5.50	5.80	6.41	6.76	7.72	8.14
Natural Gas	1.85	1.95	2.97	3.13	4.57	4.82	4.16	4.39	6.41	6.76
COM 1[3]	1.81	1.91	2.90	3.06	3.48	3.67	4.07	4.29	4.87	5.14
COM 2[3]	1.94	2.05	3.11	3.28	3.64	3.84	4.35	4.59	5.11	5.39
COM 3[3]	1.77	1.87	2.83	2.99	3.45	3.64	3.97	4.19	4.84	5.11

[1] Source: PE-348

[2] Source: US-768

[3] See Appendix D for details.

The gas and oil fuel tax portion of this program will be phased in between 1979 and 1985. For oil, the tax rate, adjusted for inflation[1], begins at \$0.19/GJ (\$0.20/10^6Btu) in 1979 and rises to \$0.93/GJ (\$0.98/10^6Btu) in 1985. For natural gas, the tax rate will be equal to the difference between the price of distillate oil and the price of natural gas. Table 5-3 presents estimated fuel costs for coal, natural gas, distillate oil, residual oil, and three coal-oil mixtures in 1978, 1985, and 1990. In addition, the costs of natural gas, oil, and COM under the proposed tax structure are presented. The before-tax fuel costs shown in Table 5-3 are based on 1978 fuel prices and a 7 percent annual escalation rate (PE-348).

The fuel taxes which are part of the National Energy Plan are only applicable to industrial users who consume over 0.53 fJ/yr (0.5 x 10^{12}Btu/yr) and these taxes are phased in between 0.53 and 1.6 fJ/yr (0.5 to 1.5 x 10^{12}Btu/yr). Therefore, consumers using less than 1.6 fJ/yr (1.5 x 10^{12} Btu/yr) pay only a fraction of the fuel taxes presented in Table 5-3. But consumers using over 1.6 fJ/yr (1.5 x 10^{12}Btu/hr) pay the full amount of the tax. The exact method for computing fuel tax as a function of consumption has not been defined. For this study, the tax rate is assumed to increase linearly between 0 and 100 percent for consumption ranging from 0.53 to 1.6 fJ/yr (0.5 to 1.5 x 10^{12}Btu/yr).

Table 5-4 presents the annual fuel consumption of the three standard boilers described in Section 5.1. As shown, only the residual oil fired unit consumes enough fuel to be impacted by the fuel tax. However, because the fuel tax applies to a fuel consumer rather than an individual boiler, the gas- and distillate oil-fired standard boilers may be impacted by the fuel tax provisions of the NEP. Unfortunately, the extent of this impact is difficult to assess because there are no data available which correlate fuel consumption of a plant and the number and type of steam generators in the plant.

---

[1] The NEP calls for a tax of \$0.14/GJ (\$0.15/10^6Btu) in 1979 and \$0.47/GJ (\$0.50/10^6Btu) in 1985 based on 1975 dollars. The costs presented here are based on 7 percent inflation.

TABLE 5-4. ANNUAL FUEL CONSUMPTION OF STANDARD BOILERS[1]

Boiler Configuration	Annual Fuel Consumption (fJ/yr)	(Btu/yr)
Gas Fired, Fire Tube	6.2	5.9×10^{10}
Distillate Oil Fired, Fire Tube	6.2	5.9×10^{10}
Residual Oil Fired, Water Tube	7.6	7.2×10^{11}

[1] Source: PE-348

The investment credit portion of the NEP permits a firm to reduce its fuel tax by investing in coal firing equipment. For each dollar invested, fuel tax will be reduced by a dollar. However, the investment in coal firing equipment will result in some increased costs. This is because the reduction of fuel taxes will increase a firm's net income. As a result of this increase in income, a firm's revenue taxes will increase. The actual costs of any investment will be the amount by which a firm's revenue taxes increase. Assuming a tax rate of 48 percent results in a capital cost of 48 cents for each dollar invested (US-768).

A quantitative analysis of how the fuel tax/investment credit program impacts the three standard boilers is difficult. This is because the fuel tax/investment credit program applies to a plant rather than an individual boiler. But since the five gas/oil to coal fuel switching methods are all investments in coal-firing equipment, the relative impact of the tax program will be similar for each fuel switching method. However, the uncertainty surrounding the quantitative impact of the tax program will prevent an accurate estimate of how many industrial boilers will switch fuels as a result of the program.

5.3 ENVIRONMENTAL IMPACT OF FUEL SWITCHING

Switching fuels from gas to oil or gas/oil to coal will result in an increase in emissions of one or more of the criteria pollutants. This section presents estimates of the emission rate of the criteria pollutants from the standard boilers before and after fuel switching. In addition, these emission rates are compared with "typical" state regulations for sulfur dioxide, nitrogen oxides, and particulates and the degree of control required to comply with these "typical" regulations is presented. The "typical" state regulations were developed by PEDCo Environmental Specialists as a result of a comprehensive survey of state air pollution laws.

5.3.1 Gas-Fired, Fire Tube Boiler

A fire tube boiler is designed to fire natural gas or distillate oil. Fuels containing ash cannot be used in these boilers because there is no practical means of keeping the heat transfer surfaces of the boiler clean without shutting down (EG-016). Therefore, only the fuel switching methods which result in combustion of ash-free fuels are applicable to fire tube boilers. These methods are:

1) gas to distillate oil, boiler modification
2) gas/oil to coal-based gas

In addition, boiler replacement is a viable method of switching fuels.

Table 5-5 presents an estimate of the uncontrolled emissions before and after switching fuels in a gas-fired, fire tube boiler. Table 5-5 also presents emission rates permitted by typical state regulations and the degree of control, expressed as percent removal, required to meet the typical regulations. Emission rates from a coal fired boiler are only

TABLE 5-5. ESTIMATED EMISSIONS AND CONTROL REQUIREMENTS FOR FUEL SWITCHING IN A GAS FIRED, FIRE TUBE BOILER

Boiler Configuration Original Design	Boiler Configuration After Fuel Switch	Pollutant	Emission Rate[1] (ng/J)	Emission Rate[1] (lb/10^6Btu)	"Typical" State Regulation[2] (ng/J)	"Typical" State Regulation[2] (lb/10^6Btu)	Degree of Control Required (% Removal)
Gas-Fired, Fire Tube	Not Applicable	particulates	1.4	3.3×10^{-3}	NA	NA	0
		sulfur dioxide	0.3	0.6×10^{-3}	NA	NA	0
		nitrogen oxides as NO_2	43	0.1	86	0.2	0
		carbon monoxide	7.3	1.7×10^{-2}	-	-	-
		hydrocarbons as CH_4	1.3	3.0×10^{-3}	-	-	-
Gas-Fired, Fire Tube	Distillate Oil-Fired, Fire Tube	particulates	9	2.1×10^{-2}	43	0.1	0
		sulfur dioxide	215	0.5	688	1.6	0
		nitrogen oxides as NO_2	86	0.2	129	0.3	0
		carbon monoxide	16	3.6×10^{-2}	-	-	-
		hydrocarbons as CH_4	3	7.2×10^{-3}	-	-	-
Gas-Fired, Fire Tube	Low/Medium-Btu Gas-Fired, Fire Tube	particulates[3]	1.4	3.3×10^{-3}	NA	NA	0
		sulfur dioxide[3]	0.3	6.0×10^{-4}	NA	NA	0
		nitrogen oxides as NO_2[3]	21-65	0.05-0.15	86	0.2	0
		carbon monoxide	7.3	1.7×10^{-2}	-	-	-
		hydrocarbons as CH_4[3]	1.3	3.0×10^{-3}	-	-	-
Gas-Fired, Fire Tube	Coal-Fired, Spreader Stoker, High Sulfur Coal	particulates	1075	2.5	258	0.6	76
		sulfur dioxide	3612	5.9	1075	2.5	70
		nitrogen oxides as NO_2	249	0.6	301	0.7	0
		carbon monoxide	37	8.5×10^{-2}	-	-	-
		hydrocarbons as CH_4	18	4.2×10^{-2}	-	-	-
Gas-Fired, Fire Tube	Coal-Fired, Spreader Stoker, Low Sulfur Western Coal	particulates	688	1.6	258	0.6	63
		sulfur dioxide	537	1.25	1075	2.5	0
		nitrogen oxides as NO_2	249	0.6	301	0.7	0
		carbon monoxide	45	10.4×10^{-2}	-	-	-
		hydrocarbons as CH_4	22	5.2×10^{-2}	-	-	-

[1] Source: PF-168 except where noted.

[2] Source: GI-155.

[3] Emission rates for low/medium-Btu gas firing are assumed equal to those of natural gas except for nitrogen oxides. The range presented for NO_x emissions is ±50 percent of the NO_x emission rate for natural gas.

presented for a spreader stoker. This is because these emission rates are similar to those from other stoker-fired units. In addition, spreader stokers represent over 50 percent of the installed stoker-fired boiler capacity. No emission rates are shown for low-sulfur eastern coal because these emissions are nearly identical to those from low-sulfur western coal (see Section 4.0).

As shown in Table 5-5, a fuel switch from natural gas to distillate oil, or low/medium-Btu gas will not require any pollution control to meet the typical state regulations. However, the emission rates presented for low/medium-Btu gas are based on fuel gas purification prior to combustion. The actual degree of gas purification will depend on the specific regulations which apply to combustion of low/medium-Btu gas.

Switching from natural gas to coal by boiler replacement will result in the requirement for some pollution control. If high sulfur coal is fired in the new boiler, both particulate and sulfur dioxide control equipment will be required. Because a relatively low degree particulate removal is needed to comply with the typical regulation, a wet scrubber designed to remove SO_2 should provide adequate particulate control. If low sulfur coal is fired in the new boiler, only particulate control will be required. Again, a relatively low degree of particulate removal is required and a low cost mechanical collector should provide adequate control.

5.3.2 Distillate Oil Fired, Fire Tube Boiler

Fuel switching in a distillate oil-fired, fire tube boiler is identical to fuel switching in a gas-fired, fire tube unit. However, the gas to oil fuel switch does not apply. Therefore, the fuel switching methods which can be employed are:

1) Boiler replacement to permit coal firing
2) Boiler modification to permit low/medium-Btu gas firing

Table 5-6 presents estimates of the emissions from the distillate oil fired standard boiler before and after fuel switching. In addition, typical state regulations and the degree of control required to comply with these regulations are included.

As shown in Table 5-6, a switch from distillate oil to low/medium Btu gas will result in a reduction of all criteria pollutant emissions from the boiler and no control equipment will be required. However, switching from distillate oil to coal by boiler replacement will result in an increase in emissions and some pollution control equipment will be required to meet the typical state regulations. If high sulfur coal is fired in the new boiler, both particulate and SO_2 control equipment will be required. By incorporating a wet scrubber into the new boiler design, emissions of these two pollutants can be reduced below the required levels. If low sulfur coal is fired in the new boiler, only particulate control will be required to comply with the typical state regulations. Because relatively low removal efficiency is required (63 percent), a low cost, mechanical collector should provide adequate control.

5.3.3 Residual Oil Fired, Water Tube Boiler

A residual oil boiler is designed to fire a fuel which contains both ash and sulfur. As a result, the presence of ash handling equipment and design parameters such as tube spacing, furnace volume, and materials of construction make a residual oil fired boiler a candidate for switching to coal by the following methods:

1) Boiler replacement to permit coal firing
2) Boiler modification to permit direct firing of coal
3) Boiler modification to permit coal-oil mixture combustion
4) Boiler modification to permit low/medium-Btu gas firing
5) Boiler modification to permit firing of coal-based liquids.

TABLE 5-6. ESTIMATED EMISSIONS AND CONTROL REQUIREMENTS FOR FUEL SWITCHING IN A DISTILLATE OIL FIRED, FIRE TUBE BOILER

Boiler Configuration		Pollutant	Emission Rate[1]		"Typical" State Regulation[2]		Degree of Control Required (% removal)
Original Design	After Fuel Switch		(ng/J)	(lb/10^6 Btu)	(ng/J)	(lb/10^6 Btu)	
Distillate Oil-Fired, Fire Tube	Not Applicable	particulates	9	2.1×10^{-2}	43	0.1	0
		sulfur dioxide	215	0.5	688	1.6	0
		nitrogen oxides as NO_2	86	0.2	129	0.3	0
		carbon monoxide	16	3.6×10^{-2}	–	–	–
		hydrocarbons as CH_4	3	7.2×10^{-3}	–	–	–
Distillate Oil-Fired, Fire Tube	Low/Medium-Btu Gas Fired, Fire Tube	particulates[3]	1.4	3.3×10^{-3}	NA	NA	0
		sulfur dioxide[3]	0.3	6.0×10^{-4}	NA	NA	0
		nitrogen oxides as NO_2[3]	21-65	0.05-0.15	86	0.2	0
		carbon monoxide[3]	7.3	1.7×10^{-2}	–	–	–
		hydrocarbons as CH_4[3]	1.3	3.0×10^{-3}	–	–	–
Distillate Oil-Fired, Fire Tube	Coal-Fired, Spreader Stoker, High Sulfur Coal	particulates	1075	2.5	258	0.6	76
		sulfur dioxide	3612	5.9	1075	2.5	70
		nitrogen oxides as NO_2	249	0.6	301	0.7	0
		carbon monoxide	37	8.5×10^{-2}	–	–	–
		hydrocarbons as CH_4	18	4.2×10^{-2}	–	–	–
Distillate Oil-Fired, Fire Tube	Coal-Fired, Spreader Stoker, Low Sulfur Western Coal	particulates	688	1.6	258	0.6	63
		sulfur dioxide	537	1.25	1075	2.5	0
		nitrogen oxides as NO_2	249	0.6	301	0.7	0
		carbon monoxide	45	0.1	–	–	–
		hydrocarbons as CH_4	22	5.2×10^{-2}	–	–	–

---

[1] Source: PE-348 except where noted.

[2] Source: GI-155.

[3] Emission rates for low/medium-Btu gas firing are assumed equal to those of natural gas except for nitrogen oxides. The range presented for NO_x emissions is ±50 percent of the emission rate for natural gas.

Table 5-7 presents an estimate of the uncontrolled emissions of criteria pollutants before and after switching fuels in a residual oil fired boiler. In addition, emission rates permitted by typical state regulations and the degree of control required to meet these regulations are included.

No separate estimates are presented in Table 5-7 for boiler replacement and boiler modification to permit direct firing of coal. This is because the emissions which result from employing either of these fuel switching methods should be identical. No estimate is presented for low-sulfur eastern coal or COM prepared with low-sulfur eastern coal. This is because emission rates and control requirements are similar to those for low-sulfur western coal. Also, Table 5-7 only contains emission estimates for one of the three coal-based liquid fuels. SRC-II is presented as representative because emissions from combustion of this fuel are similar to those which result from combustion of other coal-based liquid fuels.

As shown in Table 5-7, all but one of the six fuel switching scenarios will result in a system which requires some pollution control. The exception is a switch from residual oil to low/medium-Btu gas.

Switching to direct firing of high sulfur coal will require both particulate and sulfur dioxide control. And, if a new, coal-fired boiler is used to replace the existing residual oil boiler, the required control equipment should be included in the boiler design. However, if the boiler is modified to fire coal, sulfur dioxide and particulate control equipment may be available. This is due to the fact that the fuel characteristics of the residual oil fired standard boiler would have required some sulfur dioxide control prior to fuel switching. However, existing control equipment will have to be modified. Switching from residual oil to direct-firing of high sulfur coal more than doubles the quantity of sulfur dioxide which must be removed from the flue gas. This will significantly increase the size of both raw materials handling and waste/by-product disposal equipment.

TABLE 5-7. ESTIMATED EMISSIONS AND CONTROL REQUIREMENTS FOR FUEL SWITCHING IN A RESIDUAL OIL FIRED, WATER TUBE BOILER

Boiler Configuration		Pollutant	Emission Rate[1]		"Typical" State Regulation[2]		Degree of Control Required (% Removal)
Original Design	After Fuel Switch		(ng/J)	(lb/10^6 Btu)	(ng/J)	(lb/10^6 Btu)	
Residual Oil-Fired	Not Applicable	particulates	39	9.0×10^{-2}	43	0.1	0
		sulfur dioxide	1333	3.1	688	1.6	48
		nitrogen oxides as NO_2	129	0.3	129	0.3	0
		carbon monoxide	16	3.6×10^{-2}	-	-	-
		hydrocarbons as CH_4	3	7.2×10^{-3}	-	-	-
Residual Oil-Fired	Coal-Fired, Spreader Stoker, High Sulfur Coal	particulates	1075	2.5	258	0.6	76
		sulfur dioxide	3612	5.9	1075	2.5	70
		nitrogen oxides as NO_2	249	0.6	301	0.7	0
		carbon monoxide	37	8.5×10^{-2}	-	-	-
		hydrocarbons as CH_4	18	4.2×10^{-2}	-	-	-
Residual Oil-Fired	Coal-Fired, Spreader Stoker, Low Sulfur Western Coal	particulates	688	1.6	258	0.6	63
		sulfur dioxide	537	1.25	1075	2.5	0
		nitrogen oxides as NO_2	249	0.6	301	0.7	0
		carbon monoxide	45	10.4×10^{-2}	-	-	-
		hydrocarbons as CH_4	22	5.2×10^{-2}	-	-	-
Residual Oil-Fired	COM-Fired, Resid-High Sulfur Coal[3]	particulates	1075	2.5	150[4]	0.35[4]	86
		sulfur dioxide	1497	3.5	880[4]	2.05[4]	41
		nitrogen oxides as NO_2	194	0.45	215[4]	0.5[4]	0
		carbon monoxide	16	3.7×10^{-2}	-	-	-
		hydrocarbons as CH_4	4	9.3×10^{-3}	-	-	-
Residual Oil-Fired	COM-Fired, Resid-Low Sulfur Coal[3]	particulates	607	1.4	150[4]	0.35[4]	75
		sulfur dioxide	1020	2.4	880[4]	2.05[4]	14
		nitrogen oxides as NO_2	194	0.45	215[4]	0.5[4]	0
		carbon monoxide	17	4.0×10^{-2}	-	-	-
		hydrocarbons as CH_4	4	9.3×10^{-3}	-	-	-
Residual Oil-Fired	Low/Medium Btu Gas-Fired[6]	particulates	1.4	3.3×10^{-3}	NA	NA	0
		sulfur dioxide	0.3	0.6×10^{-3}	NA	NA	0
		nitrogen oxides as NO_2	21-65	0.05-0.15	86	0.2	0
		carbon monoxide	7.3	1.7×10^{-2}	-	-	-
		hydrocarbons as CH_4	1.3	3.0×10^{-3}	-	-	-
Residual Oil-Fired	SRC-II Fired	particulates	40	9.3×10^{-2}	43	0.1	0
		sulfur dioxide	81	0.2	688	1.6	0
		nitrogen oxides as NO_2	153-269[5]	0.35-0.63[5]	129	0.3	16-52
		carbon monoxide	15	3.5×10^{-2}	-	-	-
		hydrocarbons as CH_4	2.3	5.3×10^{-3}	-	-	-

[1] Source: PE-348 except where noted.

[2] Source: GI-155 except where noted.

[3] Emission rates for COM are based on a 50:50 coal/oil mixture by weight. See Table 4-15 for details.

[4] These values are the average of the coal and the oil standards contained in GI-155.

[5] Emissions rates are assumed equal to those of natural gas except for NO_x. The range presented is ±50 percent of the emission rate for natural gas.

[6] Source: HI-220

Switching from residual oil to direct firing of low-sulfur western coal will result in the requirement for particulate control. If boiler replacement is used to switch fuels, a mechanical collector can be included in the design to provide sufficient control. If the residual oil boiler is modified to fire coal directly, it may be necessary to retrofit a mechanical collector. However, because some SO_2 removal was required prior to the fuel switch, it may be possible to use existing equipment for particulate control.

Switching from residual oil to COM-firing will require both sulfur dioxide and particulate control in order to comply with typical state regulations. However, sulfur dioxide emissions do not change significantly as a result of switching fuels. In addition, the residual oil-fired boiler required SO_2 control prior to switching fuels. Therefore, existing SO_2 removal equipment should prove adequate for controlling SO_2 emissions from COM firing. The existing equipment may need to be augmented by a mechanical collector to provide adequate particulate removal to meet the typical state regulations.

Switching from residual fuel oil to SRC-II, a coal-based liquid fuel, will result in increased emissions of nitrogen oxides. These emissions will require some control to comply with typical state regulations. However, it does appear that combustion modifications should provide a sufficient degree of control to reduce NO_x emissions below the required level.

Table 5-8 presents a summary of the control requirements for each fuel switch discussed in this section. In addition, the control equipment which appears best suited for obtaining the required degree of removal is identified. The information on control equipment presented in Table 5-8 is used as a basis for control equipment cost estimates presented in Appendix F.

5.4 RELATIVE COSTS OF FUEL SWITCHING METHODS

In order to determine which methods are most likely to be used for switching fuels in industrial boilers, the relative costs of each fuel

TABLE 5-8. SUMMARY OF CONTROL REQUIREMENTS FOR FUEL SWITCHING IN STANDARD BOILERS

Fuel Switch	Particulates		SO_2		NO_x	
	Control Required (%)	Type of Control	Control Required (%)	Type of Control	Control Required (%)	Type of Control
Gas to Distillate Oil	None		None		None	
Gas to Low/Medium-Btu Gas	None		None		None	
Gas to High-Sulfur Coal	76	Wet scrubber	70	Wet scrubber	None	
Gas to Low-Sulfur Coal	63	Mechanical collector	None		None	
Distillate Oil to Low/Medium-Btu Gas	None		None		None	
Distillate Oil to High-Sulfur Coal	76	Wet scrubber	70	Wet scrubber	None	
Distillate Oil to Low-Sulfur Coal	63	Mechanical collector	None		None	
Residual Oil to High-Sulfur Coal	76	Wet scrubber	70	Wet scrubber	None	
Residual Oil to Low-Sulfur Coal	63	Mechanical collector	None		None	
Residual Oil to COM 1[2]	86	Mechanical collector	41	Wet scrubber[1]	None	
Residual Oil to COM 3[2]	75	Mechanical collector	14	Wet scrubber[1]	None	
Residual Oil to Low/Medium-Btu Gas	None		None		None	
Residual Oil to SRC-II	None		None		16-52	Combustion modifications

---

[1] This assumes that a wet scrubber was employed by the existing unit to reduce SO_2 emissions to levels required by typical state regulations.

[2] Analyses of these fuels are presented in Table 4-15.

fuel switching is to determine an annual cost which includes the cost of fuel, capital charges for equipment, modifications and pollution control, operating and maintenance costs, and any costs associated with current and proposed regulations. This section presents estimated annual costs for fuel switching in the three standard boilers defined in Section 5.1. For each standard boiler, annual costs are estimated for three cases. The first case estimates costs without pollution control and the second case includes an annual charge for pollution control required to reduce emissions below the level required by typical state regulations. The third case presents costs which define the potential impact of the fuel tax/investment credit program which is part of the National Energy Plan. These cost estimates are based on the capital and operating and maintenance cost estimates presented in Section 4, the fuel prices presented in Section 5.2, and additional costs which are presented in this section.

Basically, there are three major components of the annual costs of operating an industrial boiler. These components are:

1) Capital Costs,
2) Operating and Maintenance Costs, and
3) Fuel Costs.

In addition, a fourth cost associated only with fuel switching is the cost of replacing boiler capacity which may be lost as a result of a fuel switch. For the analysis presented here, the cost of replacing lost capacity is assumed to be a capital cost which equals a percentage of the capital cost of a new, coal-fired boiler. The capital cost of the new boiler used to estimate the cost of lost capacity is equal to that for a unit with a capacity of the existing boiler. The percentage of boiler costs which represents the cost of lost capacity is assumed to equal the percentage reduction in boiler capacity which results from switching fuels.

The following discussion defines the three major components of the annual cost.

Capital Costs

The capital cost component of the annual costs is determined by a capital charge rate which is based on the capital investment required to modify or replace an existing industrial boiler. This rate is a percentage of the capital cost of modification/replacement which represents, as an annual cost, a return on capital investment, depreciation of equipment, taxes, insurance, etc. PEDCo Environmental Specialists have developed a standard capital charge rate for industrial boilers. This capital charge rate varies as a function of equipment life and is defined by Equation 5-1.

$$\text{Capital Charge Rate} = \frac{0.1(1 + 0.1)^N}{(1 + 0.1)^N - 1} + 0.04 \qquad (5\text{-}1)$$

where N = number of years of equipment life

The above capital charge rate assumes a 10 percent return on investment. In addition, general and administrative costs, taxes, and insurance are assumed to be 4 percent of capital investment. For equipment with a 15 year life, the capital charge rate equals 17 percent of total capital investment and for equipment with a 30 year life, the capital charge rate equals 14.6 percent of total capital investment.

The capital charge rates defined by Equation 5-1 will be used in developing the annual costs of switching fuels. A 30 year life is assumed for all boiler replacement capital costs and a 15 year life is assumed for capital costs associated with boiler modification and pollution control equipment.

Operating and Maintenance Costs

Operating and maintenance costs consist of fixed and variable components. The fixed cost components are incurred each year, regardless of the load factor or utilization of the boiler. The variable components, on the other hand, are directly proportional to the load factor. The operating and maintenance costs used in the comparison presented here are based on costs developed by Energy and Environmental Analysis, Inc. For 4000 hrs/yr operation, these costs are presented in Section 4.0 of this report. The load factors used in computing the operating and maintenance costs are those of the standard boilers defined in Section 5.1.

Fuel Costs

Annual fuel costs are computed by multiplying the fuel price per unit of energy by the annual energy consumption of a boiler. The annual energy consumption of the three standard boilers is presented in Table 5-4. Fuel prices for natural gas, distillate and residual oil, high- and low-sulfur coal and various coal-oil mixtures are detailed in Table 5-3. However, the costs of coal-based fuels are required before the annual costs of all fuel switching methods can be computed.

Table 5-9 presents the estimated cost of low- and medium-Btu gas and coal-based liquid fuel. These costs were computed using published estimates for capital and operating costs. These published costs were adjusted to standard plant sizes by assuming that plant cost increases exponentially with size. The value of the exponent was assumed to be 0.6. A 30 year plant life is assumed which results in a capital charge rate of 14.6 percent per year. Fuel costs were based on the fuel prices presented in Table 5-3. Capital and operating costs were estimated for 1985 and 1990 by extrapolation of the Chemical Engineering Plant Cost Index. Details of how these costs were calculated appear in Appendix C.

The cost of low-Btu gas is presented for two cases which represent the the two standard boiler sizes. On-site generation of low-Btu gas is assumed. As shown in Table 5-9, low-Btu gas costs range from \$3.40 to \$7.55/GJ (\$3.59 to \$7.96/10^6Btu) in 1978. These costs are higher than most current estimates for one reason. Because the gasification facilities

TABLE 5-9. ESTIMATED COSTS OF COAL-BASED FUELS[1]

Fuel	Cost 1978		1985		1990	
	(\$/GJ)	(\$/10^6Btu)	(\$/GJ)	(\$/10^6Btu)	(\$/GJ)	(\$/10^6Btu)
Low-Btu Gas[2]						
44 MW	3.40	3.59	5.44	5.74	7.52	7.93
4.4 MW	7.55	7.96	11.93	12.59	16.52	17.43
Medium-Btu Gas[3,4]	3.21	3.39	5.12	5.40	7.14	7.53
Coal-Based Liquid Fuel[5,6]	4.89	5.16	7.74	8.17	10.82	11.42

[1] See Appendix C for details.

[2] Based on capital and operating costs from AS-068.

[3] Based on capital and operating costs from OL-065.

[4] Distribution costs are assumed to be 5 percent of product gas costs.

[5] Based on capital and operating costs from NA-419.

[6] Distribution costs are assumed to be 10 percent of product fuel costs.

are assumed to be tied directly to the boiler, the utilization of the gasifier is low (45 to 55 percent). As a result, the capital cost and fixed operating and maintenance costs are charged on a relatively small quantity of product gas. Most current estimates are based on 90 percent utilization of a gasifier which will substantially reduce the estimated gas prices.

The costs of medium-Btu gas and coal-based liquid fuels are based on a large central production facility. The capacity of these facilities is 1500 MW (∿5000 x 10^6Btu/hr) and 90 percent utilization is assumed. These costs include transportation of products from the production site to the user's plant.

5.4.1 Annual Costs - Fuel Switching in a 4.4 MW Gas-Fired, Fire Tube Boiler

There are three technically feasible fuel switching methods which can be applied to a gas fired, fire tube boiler. In addition, there are differences in fuel characteristics which result in a variation of the annual cost of switching fuels by a particular method. Combination of the three applicable fuel switching methods with the fuel characteristics examined in Section 4 results in the following fuel switching scenarios:

1) Boiler modification, natural gas to distillate oil
2) Boiler modification, natural gas to low-Btu gas
3) Boiler modification, natural gas to medium-Btu gas
4) Boiler replacement, natural gas to high-sulfur coal
5) Boiler replacement, natural gas to low-sulfur eastern coal
6) Boiler replacement, natural gas to low-sulfur western coal

Each of these scenarios represent potential fuel switches and each scenario will result in a different annual cost for boiler operation. Therefore, in order to determine which fuel switching scenarios are more likely to occur, annual costs must be determined for each one. Additional scenarios can also be developed but it appears that the six presented here are representative. However, the considerations surrounding a fuel switch are site-specific and it is impossible to account for all the variations which exist. The annual costs associated with the fuel switching scenarios defined above were estimated for three cases. In the first case, the annual costs were estimated in absence of any environmental or energy regulations. The second case presents cost estimates which include a capital charge for pollution control equipment. And for the third case, the annual costs are estimated based on the range of impacts from the fuel tax/investment credit portion of the National Energy Plan.

Case 1 - Fuel Switching Costs, No Regulations

Table 5-10 compares the estimated annual costs for six fuel switching scenarios with the cost of continuing to fire natural gas. The annual costs are divided into three cost components: capital charges, O&M costs, and fuel costs. The capital charges in Table 5-10 represent incremental costs and they do not include capital charges which are associated with the existing boiler. Costs are estimated for the years 1978, 1985, and 1990 and the cost of pollution control equipment is not included. Details of how these costs were calculated are presented in Appendix E.

The costs presented in Table 5-10 represent a base-case which defines the annual cost of operating a 4.4 MW (15 x 10^6 Btu/hr) natural gas-fired boiler before and after switching fuels. These costs do not include any charges which result from environmental or energy regulations. As shown in Table 5-10, there are no fuel switching scenarios which result in a lower annual cost than the annual cost of continuing to fire natural gas. Therefore, if fuel switching is going to occur in small, natural gas fired, fire tube boilers, the economics of boiler operation must be changed by regulations or by an additional factor such as fuel availability.

TABLE 5-10. A COMPARISON OF THE ANNUAL COSTS FOR A 4.4 MW NATURAL GAS FIRED BOILER BEFORE AND AFTER SWITCHING FUELS[1,2]

Fuel switch	Cost component	Cost ($/yr) 1978	 1985	 1990
None	Capital[3]	–	–	–
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	1.2×10^5	1.9×10^5	2.6×10^5
	Total	1.58×10^5	2.51×10^5	3.47×10^5
Natural gas to distillate oil	Capital[3]	1.1×10^4	1.7×10^4	2.4×10^4
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	1.8×10^5	2.9×10^5	4.0×10^5
	Total	2.29×10^5	3.68×10^5	5.11×10^5
Natural gas to low-Btu gas	Capital[3]	1.1×10^4	1.7×10^4	2.4×10^4
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	4.7×10^5	7.4×10^5	1.0×10^6
	Total	5.19×10^5	8.18×10^5	1.11×10^6
Natural gas to medium-Btu gas	Capital[3]	3.2×10^3	5.1×10^3	7.1×10^3
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	2.0×10^5	3.2×10^5	4.5×10^5
	Total	2.41×10^5	3.86×10^5	5.44×10^5
Natural gas to high-sulfur coal	Capital[3]	1.1×10^5	1.8×10^5	2.5×10^5
	O & M	1.7×10^5	2.7×10^5	3.8×10^5
	Fuel	4.4×10^4	7.0×10^4	9.9×10^4
	Total	3.24×10^5	5.20×10^5	7.29×10^5
Natural gas to low-sulfur eastern coal	Capital[3]	1.1×10^5	1.8×10^5	2.5×10^5
	O & M	1.7×10^5	2.7×10^5	3.8×10^5
	Fuel	6.9×10^4	1.1×10^5	1.5×10^5
	Total	3.49×10^5	5.60×10^5	7.80×10^5
Natural gas to low-sulfur western coal	Capital[3]	1.1×10^5	1.8×10^5	2.5×10^5
	O & M	1.7×10^5	2.7×10^5	3.8×10^5
	Fuel	2.5×10^4	4.0×10^4	5.6×10^4
	Total	3.05×10^5	4.90×10^5	6.86×10^5

---

[1] See Appendix E for details.

[2] Does not include pollution control costs.

[3] Capital costs represent incremental costs.

The order of preference for the fuel switching scenarios based on annual costs and in the absence of regulatory impact is as follows:

1) Natural gas to distillate oil
2) Natural gas to medium-Btu gas
3) Natural gas to low-sulfur western coal
4) Natural gas to high-sulfur coal
5) Natural gas to low-sulfur eastern coal
6) Natural gas to low-Btu gas

The cost of switching to both medium-Btu gas and distillate oil are essentially identical. Therefore, it would appear that either of these fuel switches have an equal probability of occurring. However, there are no large central gasification facilities in the U.S., so a switch to distillate oil is the most likely scenario. In the absence of regulations, this fuel switch will only occur if the boiler's natural gas supply becomes unreliable and an economic penalty is incurred as a result of the unreliability.

The annual cost which results from switching from natural gas to coal by boiler replacement is nearly constant, regardless of the type of coal fired. The costs of firing coal are approximately 50 percent higher than the costs of firing medium-Btu gas or distillate oil. Therefore, boiler replacement does not appear to be an economically feasible fuel switch for the natural gas-fired, fire tube boiler.

The cost of firing low-Btu gas is the highest of all the fuel switching scenarios examined. There are two major reasons for this. First, the cost of low-Btu gas fuel is high. This is due to the low utilization of the gasifier (45 percent) which results from tying the gasifier directly to the boiler. The second reason for the high cost of firing low-Btu gas is the capital charge associated with the boiler derating (5 percent) which occurs as a result of switching to low-Btu gas.

In summary, it appears that, in the absence of regulations, an existing 4.4 MW (15 x 10^6 Btu/hr), natural gas fired, fire tube boiler will not switch fuels if a secure supply of natural gas is available. If the natural gas supply is not secure, the most likely fuel switch to occur would be to distillate oil. Medium-Btu gas is competitive with distillate oil if the gas is produced in a large (1500 MW equivalent - 5000 x 10^6 Btu/hr) facility. However, this type of facility is not expected to have a significant impact for several years. A recent study by SRI International indicates that medium-Btu gas produced in a large central facility will account for 7.3 percent of the energy consumption of three major industries in 1985 and 13 percent by the year 2000 (OL-065).

A fuel switch from gas to coal by boiler replacement is not likely to occur. However, if no gas or oil is available, the next choice is to replace the existing boiler with a coal fired unit. Low-Btu gas is not competitive with other fuel switching methods when applied to a 4.4 MW (15 x 10^6 Btu/hr) boiler.

Case 2 - Fuel Switching Costs, Typical State Regulations

In order to determine the true annual costs of firing a variety fuels, the cost of pollution control required to meet applicable regulations must be included. However, applicable regulations vary from one location to another, so an exact determination of pollution control requirements and thus costs, is difficult. PEDCo Environmental Specialists have identified "typical" state regulations which apply to industrial boilers (GI-155). The pollution control requirements for each of the fuel switches under typical regulations are defined in Section 5.3. These requirements are used as a basis for the costs of pollution control which must be included in the cost of switching fuels.

Table 5-11 compares the estimated annual costs of six fuel switching scenarios with the cost of continuing to fire natural gas. The costs presented in Table 5-11 includes the cost of pollution control. The pollution control requirements are those identified in Table 5-8. Costs are based on estimates prepared by the Industrial Gas Cleaning Institute (IN-181) and Energy and Environmental Analysis (EN-761). A 15 year life is assumed for the pollution control equipment which results in a capital charge rate of 17 percent. Details of how the costs in Table 5-11 were derived appear in Appendix F.

TABLE 5-11. A COMPARISON OF THE ANNUAL COSTS FOR A 4.4 MW GAS FIRED BOILER BEFORE AND AFTER SWITCHING FUELS[1,2]

Fuel Switch	Annual Cost ($/yr)		
	1978	1985	1990
None	1.58×10^5	2.51×10^5	3.47×10^5
Natural gas to distillate oil	2.29×10^5	3.68×10^5	5.11×10^5
Natural gas to low-Btu gas	5.19×10^5	8.18×10^5	1.11×10^6
Natural gas to medium-Btu gas	2.41×10^5	3.86×10^5	5.44×10^5
Natural gas to high-sulfur coal	4.19×10^5	6.71×10^5	9.41×10^5
Natural gas to low-sulfur eastern coal	3.59×10^5	5.77×10^5	8.03×10^5
Natural gas to low-sulfur western coal	3.15×10^5	5.07×10^5	7.07×10^5

[1] See Appendices E and F for details.

[2] Includes cost of pollution control.

As shown in Table 5-11, the relative costs of the six fuel switching scenarios do not change markedly. In fact, the only scenarios which are impacted by pollution control costs are the fuel switches to coal. As a result of adding pollution control costs, high-sulfur coal-firing becomes the most expensive boiler replacement option and firing of any type of coal becomes less competitive on an annual cost basis. If the estimates were based on more relaxed regulations, the annual costs approach those presented in Table 5-10. Application of more restrictive pollution control regulations will only serve to make coal-firing less economically attractive and a switch to coal less likely to occur.

Case 3 - Fuel Switching Costs, Energy Regulations

In addition to the costs which result from environmental regulations, the annual costs of switching fuels in an existing 4.4 MW (15 x 10^6 Btu/hr) gas fired fire tube boiler may be impacted by provisions of the National Energy Plan which are currently under consideration. The provisions of the NEP are detailed in Section 5.2 but the impact of these provisions on the three standard boilers cannot be quantified. This is due to the fact that the proposed fuel tax/investment credit portion of the NEP is site-specific rather than being specific to a particular size of boiler (US-768).

In order to estimate the potential impact of the fuel tax/investment credit portion of the NEP, two cases were examined. The first assumes that only the minimum fuel tax is paid and no investment credit is received. For the 4.4 MW (15 x 10^6 Btu/hr) boiler, the annual costs which result from this assumption are identical to those presented in Table 5-11. The second case assumes that tax is paid on all fuel used by the boiler and the capital investment required to switch to coal is completely covered by investment credit. Annual costs for these two cases are presented in Table 5-12 and details of how these costs were determined appear in Appendices C, D, and E.

The costs presented in Table 5-12 are for the years 1985 and 1990. Although the fuel tax/investment credit program is scheduled to begin in 1979, it will not be fully implemented until 1985 (US-768). As shown in Table 5-12, the full impact of the NEP will effect the six fuel switching scenarios in two ways. First, the cost of firing natural gas and distillate oil increases significantly. As a result, the cost of firing medium-Btu gas becomes competitive with the cost of firing natural gas. Second, the annual

TABLE 5-12. RANGE OF POTENTIAL IMPACT FROM THE FUEL TAX/INVESTMENT CREDIT PROGRAM ON THE ANNUAL COSTS OF A 4.4 MW GAS FIRED BOILER[1,2]

Fuel Switch	Annual Cost ($/yr)			
	Minimum Fuel Tax No Investment Credit		Maximum Fuel Tax Maximum Investment Credit	
	1985	1990	1985	1990
None	2.51×10^5	3.47×10^5	3.51×10^5	4.87×10^5
Natural gas to distillate oil	3.68×10^5	5.11×10^5	4.18×10^5	5.91×10^5
Natural gas to low-Btu gas	8.18×10^5	1.11×10^6	4.99×10^5	6.98×10^5
Natural gas to medium-Btu gas	3.86×10^5	5.44×10^5	3.89×10^5	5.48×10^5
Natural gas to high-sulfur coal	6.71×10^5	9.41×10^5	5.27×10^5	7.42×10^5
Natural gas to low-sulfur eastern coal	5.77×10^5	8.03×10^5	4.73×10^5	6.63×10^5
Natural gas to low-sulfur western coal	5.07×10^5	7.07×10^5	4.03×10^5	5.67×10^5

---

[1] See Appendices E and F for details.

[2] Includes the cost of pollution control.

cost of firing coal is reduced and, as a result, this fuel switching option becomes competitive with distillate oil firing for the low-sulfur western coal scenario.

Although the fuel tax/investment credit program does change the relative economics of the six fuel switching options, the cost of continuing to fire natural gas and the limited supply of medium-Btu gas will restrict fuel switching. And since the costs shown in Table 5-12 represent the maximum impact of the fuel tax/investment credit program, a small fraction of the existing 4.4 MW (15×10^6 Btu/hr) natural gas-fired, fire tube boilers may find medium-Btu gas firing economical. Therefore, the extent of fuel switching in small gas-fired boilers will be determined by fuel availability. The fuel switching scenarios which are most likely to occur if natural gas is not available are:

1) Natural gas to low-sulfur western coal
2) Natural gas to distillate oil
3) Natural gas to low-sulfur eastern coal

Because distillate oil may also be difficult to obtain, the most probable fuel switch will be to low-sulfur western coal.

5.4.2 Annual Costs - Fuel Switching in a 4.4 MW Distillate Oil-Fired Fire Tube Boiler

There are two technically feasible fuel switching methods which can be applied to a distillate oil fired, fire tube boiler. In addition, there are differences in fuel characteristics which result in a variation of the annual cost of switching fuels. Combination of the two applicable fuel switching methods with the fuel characteristics examined in Section 4 results in the following fuel switching scenarios:

1) Boiler modification, distillate oil to low-Btu gas
2) Boiler modification, distillate oil to medium-Btu gas

3) Boiler replacement, distillate oil to high-sulfur coal
4) Boiler replacement, distillate oil to low-sulfur eastern coal
5) Boiler replacement, distillate oil to low-sulfur western coal

Each of these scenarios represent potential fuel switches and each scenario will result in a different annual cost for boiler operation.

Annual costs were estimated for each of the five scenarios defined above and these costs were examined for three cases. The first case estimates the annual costs associated with firing various fuels in absence of any environmental or energy regulations. The second case presents cost estimates which include a capital charge for pollution control equipment which is required to meet typical state regulations. And for the third case, annual costs are estimated based on the provisions of the fuel tax/investment credit program which is part of the National Energy Plan.

Case 1 - Fuel Switching Costs, No Regulations

Table 5-13 compares the estimated annual costs for the five fuel switching scenarios defined above. The annual costs are divided into three components: capital charges, O&M costs, and fuel costs. The capital charges in Table 5-13 represent incremental costs associated with fuel switching and they do not include capital charges for the existing boiler. Costs are estimated for the years 1978, 1985, and 1990. Capital charges and O&M costs were developed for the years 1985 and 1990 by extrapolation of the Chemical Engineering Plant Cost Index. Mid-year values for the index were estimated to be 345 and 480 for 1985 and 1990, respectively. No costs are included for pollution control but a capital charge is included to account for boiler derating. Details of how the costs in Table 5-13 were calculated appear in Appendix E.

As shown in Table 5-13, there are no fuel switching scenarios which have an annual cost lower than that resulting from continued combustion of

TABLE 5-13. A COMPARISON OF THE ANNUAL COSTS FOR A 4.4 MW DISTILLATE OIL FIRED BOILER BEFORE AND AFTER SWITCHING FUELS[1,2]

Fuel Switch	Cost Component	Cost ($/yr) 1978	1985	1990
None	Capital[3]	-	-	-
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	1.8×10^5	2.9×10^5	4.0×10^5
	Total	2.18×10^5	3.51×10^5	4.87×10^5
Distillate oil to low-Btu gas	Capital[3]	6.8×10^4	1.1×10^5	1.5×10^5
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	4.7×10^5	7.4×10^5	1.0×10^6
	Total	5.76×10^5	9.11×10^5	1.24×10^6
Distillate oil to medium-Btu gas	Capital[3]	2.2×10^4	3.6×10^4	4.9×10^4
	O & M	3.8×10^4	6.1×10^4	8.7×10^4
	Fuel	2.0×10^5	3.2×10^5	4.5×10^5
	Total	2.60×10^5	4.17×10^5	5.86×10^5
Distillate oil to high-sulfur coal	Capital[3]	1.1×10^5	1.8×10^5	2.5×10^5
	O & M	1.7×10^5	2.7×10^5	3.8×10^5
	Fuel	4.4×10^4	7.0×10^4	9.9×10^4
	Total	3.24×10^5	5.20×10^5	7.29×10^5
Distillate oil to low-sulfur eastern coal	Capital[3]	1.1×10^5	1.8×10^5	2.5×10^5
	O & M	1.7×10^5	2.7×10^5	3.8×10^5
	Fuel	6.9×10^4	1.1×10^5	1.5×10^5
	Total	3.49×10^5	5.60×10^5	7.80×10^5
Distillate oil to low-sulfur western coal	Capital[3]	1.1×10^5	1.8×10^5	2.5×10^5
	O & M	1.7×10^5	2.7×10^5	3.8×10^5
	Fuel	2.5×10^4	4.0×10^4	5.6×10^4
	Total	3.05×10^5	4.90×10^5	6.86×10^5

---

[1] See Appendix E for details.

[2] Does not include pollution control costs.

[3] Capital costs represent incremental costs.

distillate oil. And while the cost of medium-Btu gas combustion is close to that of distillate oil firing, the use of medium-Btu gas is expected to be limited.

The order of preference for the fuel switching scenarios based on annual costs is as follows:

1) Distillate oil to medium-Btu gas
2) Distillate oil to low-sulfur western coal
3) Distillate oil to high-sulfur coal
4) Distillate oil to low-sulfur eastern coal
5) Distillate oil to low-Btu gas

The annual costs of firing coal are nearly constant regardless of the fuel characteristics. These costs are approximately 50 percent higher than the cost of firing distillate oil. Therefore, boiler replacement does not appear to be an economically feasible fuel switching method for a 4.4 MW distillate oil-fired, fire tube boiler. However, if a fuel switch is required for reasons of fuel availability, the most likely scenario will be a switch to coal by boiler replacement.

The annual cost of firing low-Btu gas is nearly three times the annual cost of distillate oil firing. The reasons for this are the high cost of producing low-Btu gas and the estimated boiler derating (50 percent) (BA-477) which results when low-Btu gas is fired in an existing oil boiler.

In summary, in the absence of regulations, fuel switching is not economically feasible in a 4.4 MW (15 x 10^6 Btu/hr) distillate oil fired, fire tube boiler. Firing medium-Btu gas is competitive but no facilities currently produce this fuel. Projections indicate medium-Btu gas will have a limited penetration into the U.S. fuels market by 1985. Switching to coal firing is not economically attractive but if distillate oil supplies become insecure, this fuel switch will occur. Low-Btu gas firing is not competitive with other fuel switching options and it results in almost a 300 percent increase in annual costs for the boiler.

Case 2 - Fuel Switching Costs, Typical State Regulations

Table 5-14 compares the estimated annual costs for five fuel switching scenarios with the annual costs of operating a 4.4 MW (15×10^6 Btu/hr) distillate oil-fired, fire tube boiler. The costs presented in Table 5-14 include capital charges for pollution control equipment. The degree of control required and the type of pollution control equipment used are defined in Table 5-8. Details of how pollution control costs were calculated appear in Appendix F.

TABLE 5-14. A COMPARISON OF THE ANNUAL COSTS FOR A 4.4 MW DISTILLATE OIL FIRED BOILER BEFORE AND AFTER SWITCHING FUELS[1,2]

Fuel Switch	Annual Cost ($/yr)		
	1978	1985	1990
None	2.18×10^5	3.51×10^5	4.87×10^5
Distillate oil to low-Btu gas	5.76×10^5	9.11×10^5	1.24×10^6
Distillate oil to medium-Btu gas	2.60×10^5	4.17×10^5	5.86×10^5
Distillate oil to high-sulfur coal	4.19×10^5	6.71×10^5	9.41×10^5
Distillate oil to low-sulfur eastern coal	3.59×10^5	5.77×10^5	8.03×10^5
Distillate oil to low-sulfur western coal	3.15×10^5	5.07×10^5	7.07×10^5

[1] See Appendices E and F for details.

[2] Includes the cost of pollution control.

Addition of capital charges for pollution control equipment does not significantly change the annual costs of the five fuel switching scenarios examined. In fact, the annual costs of firing both low- and medium-Btu gas do not change and the cost of firing the low-sulfur coals increases by less than 5 percent. Only the high-sulfur coal costs are impacted by pollution control costs. The addition of capital charges for pollution control makes high-sulfur coal firing the most expensive of the three coal firing scenarios, but low-Btu gas combustion still has the highest annual cost.

It must be emphasized that the costs presented in Table 5-14 are based on the typical state regulations identified in Section 5.3. If more restrictive regulations are applied to the fuel switching scenarios, the cost of firing coal becomes higher. If more relaxed regulations are applied, the cost of firing high-sulfur coal will decline while the costs of firing low sulfur coal should not change significantly. However, regardless of the degree of control required, it appears that the relative costs of firing distillate oil, medium-Btu gas, coal, and low-Btu gas will not change.

Case 3 - Fuel Switching Costs, Energy Regulations

The fuel tax/investment credit program which is part of the National Energy Plan has the potential to impact the annual cost of operating a boiler (US-768). However, because the fuel tax/investment credit program is site specific rather than specific to a class of boilers, its impact on annual costs cannot be quantified. In order to estimate the potential impact, the annual costs of firing various fuels were estimated for two cases. The first case determines what the minimum impact of the tax program will be. For a 4.4 MW (15×10^6 Btu/hr) distillate oil fired, fire tube boiler, there is no impact. No fuel tax is incurred because of the low annual fuel consumption by the boiler. In addition, no investment credit is available. The second case estimates what the maximum impact of the tax program might be. In this case, all the oil consumed is subject to the maximum tax rate and all capital investments in coal-firing equipment, including on-site gasification, are eligible for investment credit. This case could only occur if the distillate oil fired boiler is part of a large industrial complex which consumes 1.6 fJ/yr (1.5×10^{12} Btu/yr) or more of natural gas, distillate, or residual oil (US-768).

Table 5-15 compares the estimated annual costs for five fuel switching scenarios with the cost of firing distillate oil under the two cases defined above. The first case is identical to the costs presented in Table 5-14 while the second case reflects the full impact of the fuel tax/investment credit program. As shown, the second case results in changes in the relative costs of firing various fuels. Medium-Btu gas firing becomes the lowest cost scenario and firing low-sulfur western coal becomes competitive with distillate oil firing. The annual cost of firing low-sulfur eastern coal is about 20 percent above that of western coal, but it may be attractive in some areas of the country. High-sulfur coal and low-Btu gas firing still do not appear attractive. The change in the relative costs of firing fuels will have several impacts. First, the low cost of medium-Btu gas should encourage the construction of central gasification facilities. Second, because the cost of firing low-sulfur coal is essentially equal to the cost of firing distillate oil, distillate oil fired boilers which are retired will tend to be replaced with coal-fired units. This is especially true if the supply of distillate oil becomes uncertain. However, it appears unlikely that a significant fraction of the distillate oil-fired, fire tube boilers will be subject to the full impact of the fuel tax/investment credit program. Therefore, no significant fuel switches are expected in the class of boilers represented by the 4.4 MW (15×10^6 Btu/hr) unit.

5.4.3 Annual Costs - Fuel Switching in a 44 MW Residual Oil-Fired Water Tube Boiler

There are five technically feasible fuel switching methods which can be applied to a residual oil-fired, water tube boiler. In addition, there are differences in fuel characteristics which result in a variation of the

TABLE 5-15. RANGE OF POTENTIAL IMPACT FROM THE FUEL TAX/INVESTMENT CREDIT PROGRAM ON THE ANNUAL COSTS OF A 4.4 MW DISTILLATE OIL FIRED BOILER[1,2]

Fuel Switch	Annual Cost ($/yr)			
	Minimum Fuel Tax No Investment Credit		Maximum Fuel Tax Maximum Investment Credit	
	1985	1990	1985	1990
None	3.51×10^5	4.87×10^5	4.01×10^5	5.67×10^5
Distillate oil to low-Btu gas	9.11×10^5	1.24×10^6	5.42×10^5	7.59×10^6
Distillate oil to medium-Btu gas	4.17×10^5	5.86×10^5	3.98×10^5	5.61×10^5
Distillate oil to high-sulfur coal	6.71×10^5	9.41×10^5	5.27×10^5	7.42×10^5
Distillate oil to low-sulfur eastern coal	5.77×10^5	8.03×10^5	4.73×10^5	6.63×10^5
Distillate oil to low-sulfur western coal	5.07×10^5	7.07×10^5	4.03×10^5	5.67×10^5

[1] See Appendices E and F for details.

[2] Includes the cost of pollution control.

annual costs of switching fuels. Combination of the five applicable fuel switching methods with the fuel characteristics examined in Section 4 results in fourteen fuel switching scenarios, nine of which are listed below.

1) Boiler modification, residual oil to low-Btu gas
2) Boiler modification, residual oil to medium-Btu gas
3) Boiler modification, residual oil to COM 1
4) Boiler modification, residual oil to COM 2
5) Boiler modification, residual oil to COM 3
6) Boiler modification, residual oil to coal-based liquid fuel
7) Boiler replacement, residual oil to high-sulfur coal
8) Boiler replacement, residual oil to low-sulfur eastern coal
9) Boiler modification, residual oil to low-sulfur western coal

For each of the nine fuel switching scenarios listed, annual costs were estimated. Costs were not estimated for boiler modification to permit firing various coals and boiler modification to permit firing of specific coal-based liquid fuels.

The reason costs are not presented for modification to permit coal firing is because costs are essentially equal to the costs of boiler replacement. Therefore, it seems unlikely that any existing boilers will be modified to permit coal firing unless the capability to fire coal was included in the boiler design. And, while the survey of MFBI's indicates that 22 percent of existing MFBI's were designed with coal capability, it is impossible to estimate the costs of reconverting these units.

Costs were not estimated for the three coal based liquid fuels discussed in Section 4 because no cost data for production of these fuels were available. Instead, a general cost estimate for production of coal based liquid fuels by a solvent extraction, catalytic hydrogenation liquefaction process was used. Therefore, the scenario which examines coal-based liquid fuel is not representative of any specific process. Rather, the costs are assumed to be representative of liquefaction technology in general.

Annual costs of the nine fuel switching scenarios defined above are estimated for three cases. In the first case, costs are estimated without consideration of the impact of current or proposed environmental and energy regulations. This defines base-line annual costs for the fuel switching scenarios. The second case presents estimated annual costs for the fuel switching scenarios which include pollution control equipment. The degree of control required and the type of control equipment used are defined in Table 5-8. The third case projects a range of annual costs which may result from implementation of the proposed fuel tax/investment credit program which is part of the National Energy Plan.

Case 1 - Fuel Switching Costs, No Regulations

Table 5-16 compares the estimated annual costs for nine fuel switching scenarios with the cost of continuing to fire residual oil in an existing 44 MW (150 x 10^6 Btu/hr) water tube boiler. Based on the costs presented in Table 5-15, the order of preference for the fuel switching scenarios is:

1) Residual oil to low-sulfur western coal
2) Residual oil to COM 3
3) Residual oil to COM 1
4) Residual oil to COM 2
5) Residual oil to high-sulfur coal
6) Residual oil to low-sulfur eastern coal
7) Residual oil to medium-Btu gas
8) Residual oil to low-Btu
9) Residual oil to coal-based liquid fuel.

As shown in Table 5-16, the annual costs of the first five scenarios are competitive with the cost of continuing to fire residual oil. Within the accuracy of the cost estimates, the annual costs of firing high-sulfur coal, low-sulfur western coal, COM, and residual oil are equal. The cost of firing low-sulfur eastern coal, medium-Btu gas, low-Btu gas, and coal-based liquid

TABLE 5-16. A COMPARISON OF THE ANNUAL COSTS FOR A 44 MW RESIDUAL OIL FIRED BOILER BEFORE AND AFTER SWITCHING FUELS[1,2]

Fuel Switch	Cost Component	Annual Cost ($/yr) 1978	1985	1990
None	Capital[3]	–	–	–
	O & M	7.7×10^4	1.2×10^5	1.7×10^5
	Fuel	1.6×10^6	2.6×10^6	3.6×10^6
	Total	1.68×10^6	2.72×10^6	3.77×10^6
Residual oil to low-Btu gas	Capital[3]	5.3×10^5	8.3×10^5	1.2×10^6
	O & M	7.7×10^4	1.2×10^5	1.7×10^5
	Fuel	2.6×10^6	4.1×10^6	5.7×10^6
	Total	3.21×10^6	5.05×10^6	7.07×10^6
Residual oil to medium-Btu gas	Capital[3]	1.7×10^5	2.6×10^5	3.7×10^5
	O & M	7.7×10^4	1.2×10^5	1.7×10^5
	Fuel	2.4×10^6	3.9×10^6	5.4×10^6
	Total	2.65×10^6	4.28×10^6	5.94×10^6
Residual oil to COM 1	Capital[3]	1.1×10^4	1.9×10^4	2.6×10^4
	O & M	1.9×10^5	3.0×10^5	4.2×10^5
	Fuel	1.4×10^6	2.2×10^6	3.1×10^6
	Total	1.60×10^6	2.52×10^6	3.55×10^6
Residual oil to COM 2	Capital[3]	1.1×10^4	1.9×10^4	2.6×10^4
	O & M	1.9×10^5	3.0×10^5	4.2×10^5
	Fuel	1.5×10^6	2.4×10^6	3.3×10^6
	Total	1.70×10^6	2.72×10^6	3.75×10^6
Residual oil to COM 3	Capital[3]	1.1×10^4	1.9×10^4	2.6×10^4
	O & M	1.9×10^5	3.0×10^5	4.2×10^5
	Fuel	1.4×10^6	2.2×10^6	3.0×10^6
	Total	1.60×10^6	2.52×10^6	3.45×10^6
Residual oil to coal-based liquid fuel	Capital[3]	2.2×10^5	3.4×10^5	4.9×10^5
	O & M	7.7×10^4	1.2×10^5	1.7×10^5
	Fuel	3.7×10^6	5.9×10^6	8.2×10^6
	Total	4.00×10^6	6.36×10^6	8.86×10^6
Residual oil to high-sulfur coal	Capital[3]	8.6×10^5	1.4×10^6	1.9×10^6
	O & M	3.2×10^5	5.1×10^5	7.1×10^5
	Fuel	5.3×10^5	8.6×10^5	1.2×10^6
	Total	1.71×10^6	2.77×10^6	3.81×10^6
Residual oil to low-sulfur eastern coal	Capital[3]	8.6×10^5	1.4×10^6	1.9×10^6
	O & M	3.2×10^5	5.1×10^5	7.1×10^5
	Fuel	8.4×10^5	1.3×10^6	1.9×10^6
	Total	2.02×10^6	3.21×10^6	4.51×10^6
Residual oil to low-sulfur western coal	Capital[3]	8.6×10^5	1.4×10^6	1.9×10^6
	O & M	3.2×10^5	5.1×10^5	7.1×10^5
	Fuel	3.0×10^5	4.8×10^5	6.8×10^5
	Total	1.48×10^6	2.39×10^6	3.29×10^6

[1] See Appendix E for details.
[2] Does not include pollution control costs.
[3] Capital costs represent incremental costs.

fuels are not competitive with the other fuel switching scenarios. Details of how the costs presented in Table 5-16 were calculated appear in Appendix E.

Although the values presented for annual costs in Table 5-16 indicate that some of the fuel switching scenarios do have lower annual costs than those associated with firing residual oil, the accuracy of the cost estimates and the bases used in developing these estimates make it impossible to distinguish between the costs of firing residual oil, high-sulfur coal, low-sulfur western coal, and COM. Therefore no significant fuel switching is expected based on the costs in Table 5-16. If any fuel switching does occur, it will be a result of a site specific analysis which is the only method of accurately defining costs associated with various fuel switching scenarios. Also, the costs presented in Table 5-16 do not include any pollution control equipment and therefore they do not reflect the costs which will be incurred if an existing boiler which switches fuels must comply with state regulations.

Case 2 - Fuel Switching Costs, Typical State Regulations

Table 5-17 compares the estimated annual costs for nine fuel switching scenarios with the annual costs of operating a 44 MW (150 x 10^6 Btu/hr) residual oil-fired, water tube boiler. These costs include capital charges for pollution control equipment which is required to reduce the level of criteria pollutant emissions below that permitted by typical state regulations. As shown in Table 5-17, the cost of firing low-sulfur western coal and all three coal-oil mixtures remain competitive with the cost of continuing to fire residual oil even when capital charges for pollution control equipment are included in annual costs. In fact, the scenario in which high-sulfur coal is fired is the only case in which a significant change in costs results from applying pollution control equipment. This is because firing high-sulfur coal requires a flue gas desulfurization system in order to comply with the SO_2 emission limits defined by the typical state regulations. The cost of firing low-sulfur coal and COM increases by less than 5 percent because only a moderate degree (less than 90 percent removal) of particulate control and no additional SO_2 controls are required.

TABLE 5-17. A COMPARISON OF THE ANNUAL COSTS FOR A 44 MW RESIDUAL OIL FIRED BOILER BEFORE AND AFTER SWITCHING FUELS^{1,2}

Fuel Switch	Annual Cost ($/yr)		
	1978	1985	1990
None	1.68×10^6	2.72×10^6	3.77×10^6
Residual oil to low-Btu gas	3.21×10^6	5.05×10^6	7.07×10^6
Residual oil to medium-Btu gas	2.65×10^6	4.28×10^6	5.94×10^6
Residual oil to COM 1	1.66×10^6	2.60×10^6	3.66×10^6
Residual oil to COM 2	1.76×10^6	2.80×10^6	3.86×10^6
Residual oil to COM 3	1.66×10^6	2.60×10^6	3.56×10^6
Residual oil to coal-based liquid fuel	4.03×10^6	6.40×10^6	8.92×10^6
Residual oil to high-sulfur coal	2.34×10^6	3.77×10^6	5.21×10^6
Residual oil to low-sulfur eastern coal	2.08×10^6	3.29×10^6	4.62×10^6
Residual oil to low-sulfur western coal	1.54×10^6	2.47×10^6	3.40×10^6

[1] See Appendices E and F for details.

[2] Includes the cost of pollution control.

If more restrictive environmental regulations are applied to the fuel switching scenarios, firing low-sulfur western coal and COM will become less competitive with continued firing of residual oil and a fuel switch will be less likely. If more relaxed environmental regulations are applied to the fuel switching scenarios, no major changes will occur. The only scenario which will be impacted is high-sulfur coal firing. Less restrictive regulations will make this scenario more competitive with residual oil firing.

Case 3 - Fuel Switching Costs, Energy Regulations

The fuel tax/investment credit program which is part of the National Energy Plan will impact the annual cost of operating a 44 MW (150 x 10^6 Btu/hr) boiler. However, because the fuel tax/investment credit program is site specific rather than specific to a single boiler, it is difficult to quantify the impact of the program on annual costs (US-768). In order to determine what the impact of the tax program might be, the annual costs of firing various fuels were estimated for two cases. The first case determines what the minimum impact of the tax program will be. This assumes that the boiler under consideration is the only unit located at a particular site. For a 44 MW (150 x 10^6 Btu/hr) residual oil-fired boiler with a load factor of 55 percent, the oil burned will be subject to 23 percent of the full fuel tax rate defined in Table 5-3. This assumes that the tax rate increases linearly from 0 to 100 percent of the maximum as annual fuel consumption increases from 0.53 to 1.6 fJ/yr (0.5 to 1.5 x 10^{12} Btu/yr). No investment credit is given to capital expenditures for coal firing equipment in this case.

The maximum impact of the fuel tax/investment credit program is also estimated. This case assumes that the 44 MW (150 x 10^6 Btu/hr) residual oil boiler is part of a larger fuel burning installation which consumes more than 1.6 fJ/yr (1.5 x 10^{12} Btu/yr) of gas and oil. In addition, it is assumed that all capital investment in coal firing equipment including modifications required to permit firing of COM and coal-based gas and liquid fuels are eligible for full investment credit.

Table 5-18 presents estimated annual costs for firing various fuels under the minimum and maximum impacts of the fuel tax/investment credit program. Under the minimum impact case, only the cost of firing residual oil is affected and this cost increases by less than 5 percent. Under the maximum impact case, significant changes occur in the relative costs of firing various fuels. The annual cost of firing low-sulfur western coal by boiler replacement is approximately 50 percent of the cost of firing residual oil. In addition, the annual costs of firing low-sulfur eastern coal, high-sulfur coal, low-Btu gas, and the three coal-oil mixtures are over 15 percent lower than the cost of continuing to fire distillate oil. Details of how these costs were calculated appear in Appendices E and F.

There are several reasons why the relative costs of firing various fuels changes so markedly. First, the fuel tax results in nearly a 50 percent increase in the annual cost of firing residual oil. Second, the annual cost of firing coal is reduced approximately 30 percent due to the investment credit, which is applied to the capital charges associated with the boiler and pollution control equipment. The cost of producing low-Btu gas is also reduced because investment credit is applied to the capital cost of the gasifier. Third, although the cost of COM firing increases due to the fuel tax on the oil which is used to prepare the mixture, coal comprises a significant fraction (50 percent by weight) of the fuel. As a result, COM costs only increase 25 percent as compared to nearly 50 percent for residual oil. In addition, the capital cost of converting to COM firing is reduced by the investment credit.

The cost of converting to both medium-Btu gas and coal-based liquid fuel are not changed significantly. This is due to the fact that these fuels are produced in a large central facility which is not eligible for an investment credit.

The annual costs presented in Table 5-18 indicate that the NEP can have a significant impact on the cost of firing various fuels in an existing 44 MW (150×10^6 Btu/hr) residual oil fired boiler. The minimum impact of the tax will make both coal and COM firing economically attractive. The most probable result of this will be that if a boiler is ready to be retired, it will be replaced with a low-sulfur, coal-fired unit. And, if COM firing becomes a developed technology, there will be a definite economic incentive for its use.

TABLE 5-18. RANGE OF POTENTIAL IMPACT FROM THE FUEL TAX/INVESTMENT CREDIT PROGRAM ON THE ANNUAL COSTS OF A 44 MW RESIDUAL OIL FIRED BOILER[1,2]

Fuel Switch	Annual Cost ($/yr)			
	Minimum Fuel Tax No Investment Credit		Maximum Fuel Tax Maximum Investment Credit	
	1985	1990	1985	1990
None	2.82×10^6	3.97×10^6	3.42×10^6	4.77×10^6
Residual oil to low-Btu gas	5.05×10^6	7.07×10^6	3.42×10^6	4.72×10^6
Residual oil to medium-Btu gas	4.28×10^6	5.94×10^6	4.14×10^6	5.75×10^6
Residual oil to COM 1	2.60×10^6	3.66×10^6	3.06×10^6	4.20×10^6
Residual oil to COM 2	2.80×10^6	3.86×10^6	3.16×10^6	4.40×10^6
Residual oil to COM 3	2.60×10^6	3.56×10^6	2.96×10^6	4.20×10^6
Residual oil to coal based liquid fuel	6.40×10^6	8.92×10^6	6.09×10^6	8.48×10^6
Residual oil to high-sulfur coal	3.77×10^6	5.21×10^6	2.75×10^6	3.82×10^6
Residual oil to low-sulfur eastern coal	3.29×10^6	4.62×10^6	2.52×10^6	3.59×10^6
Residual oil to low-sulfur western coal	2.47×10^6	3.40×10^6	1.70×10^6	2.37×10^6

[1] See Appendices E and F for details.

[2] Includes the cost of pollution control.

The maximum impact of the fuel tax/investment credit program will be to make fuel switching from residual oil to coal, COM and low-Btu gas very attractive from an economic standpoint. Of these fuel switches, conversion to coal firing via boiler replacement is the most probable scenario. However, if a firm is unable to raise capital for a new boiler and if the technology becomes established, a switch to COM firing will occur. Switching fuels from residual oil to low-Btu gas is attractive but it is the least likely of the options examined and this scenario will probably only occur in isolated cases. Switching fuels to either medium-Btu gas or a coal-based liquid fuel do not appear to be economically attractive options for the 44 MW (150 x 10^6 Btu/hr) residual oil fired water tube boiler.

5.5 EXPECTED FUEL SWITCHES

Estimation of the number and type of fuel switching which will occur in existing industrial boilers is a complex problem. Fuel switching is influenced by many factors including energy regulations, environmental considerations, costs, fuel availability, boiler characteristics, boiler location, plant size, etc. The impact of energy regulations, environmental considerations, and costs have been examined for the following boilers:

1) 4.4 MW (15 x 10^6 Btu/hr) natural gas-fired, fire tube boiler
2) 4.4 MW (15 x 10^6 Btu/hr) distillate oil-fired, fire tube boiler
3) 44 MW (150 x 10^6 Btu/hr) residual oil-fired, water tube boiler

However, data are not available to permit a detailed examination of some of the other factors which can influence fuel switching. As a result, an estimate can be made of the expected, or most probable, fuel switches under a specific set of conditions. But, the number of boilers which will switch fuels by a particular method cannot be determined. Quantification of fuel switching requires site specific data which are not available.

This section identifies the fuel switches which are expected to occur in the three standard boilers. The expected fuel switches are identified under the following four sets of conditions:

1) No regulations apply to boiler.
2) Boiler must comply with "typical" state regulations by addition of pollution control equipment.
3) Boiler must comply with "typical" state regulations and the minimum impact of the fuel tax/investment credit program on annual costs is estimated.
4) Boiler must comply with "typical" state regulations and the maximum impact of the fuel tax/investment credit program on annual costs is estimated.

In addition, to identify expected fuel switches, this section estimates the design parameters for the three standard boilers after fuel switching.

5.5.1 4.4 MW Natural Gas-Fired, Fire Tube Boiler

The annual costs associated with fuel switching in a 4.4 MW (15 x 10^6 Btu/hr) natural gas fired, fire tube boiler were estimated for four sets of conditions. Based on these estimates, the expected fuel switches were determined and are presented in Table 5-19. As shown, the natural gas-fired boiler is not expected to switch fuels. However, if any fuel switch will take place, distillate oil and medium-Btu gas are the most probable choices. A switch to low-sulfur western coal is also likely where the fuel tax/investment credit program has maximum impact. However, these fuel switches will not occur unless a serious natural gas supply problem is encountered and the industrial boiler operator incurs a cost penalty as a result of supply interruptions.

Table 5-20 presents estimated values for the design parameters of the 4.4 MW (15 x 10^6 Btu/hr) natural gas-fired boiler after switching fuels to distillate oil, medium-Btu gas, and low-sulfur coal. Pollutant rates are for uncontrolled emissions. The values presented in Table 5-20 are based on the information which is contained in Section 4.0 of this report and on the design parameters for standard boilers prepared by PEDCo Environmental Specialists Inc. (PE-348).

TABLE 5-19. EXPECTED FUEL SWITCHES FOR A 4.4 MW NATURAL GAS-FIRED BOILER

Rank[1]	Basis			
	No Regulations	Typical State Regulations	Minimum Impact of NEP	Maximum Impact of NEP
1st	None	None	None	None
2nd	Distillate oil	Distillate oil	Distillate oil	Medium-Btu gas
3rd	Medium-Btu gas	Medium-Btu gas	Medium-Btu gas	Low-sulfur western coal

[1] The rank is based on the annual costs in Tables 5-10, 5-11, and 5-12.

5.5.2 4.4 MW Distillate Oil Fired, Fire Tube Boiler

The annual costs associated with fuel switching in a 4.4 MW (15 x 10^6 Btu/hr) distillate oil-fired, fire tube boiler were estimated for four sets of conditions. Based on these estimates, the expected fuel switches were identified and are presented in Table 5-21. As shown, the distillate oil fired boiler should not switch fuels except under the maximum impact of the fuel tax/investment credit portion of the National Energy Plan. Under maximum impact of the NEP, a switch to medium-Btu gas is expected based on costs. However, only a small fraction of existing boilers will switch to medium-Btu gas. This is because a limited supply of medium-Btu gas is projected through the year 2000.

Table 5-21 indicates that under the conditions of no regulations, typical state regulations, and minimum impact of the National Energy Plan,

TABLE 5-20. DESIGN PARAMETERS FOR A 4.4 MW NATURAL GAS FIRED BOILER AFTER SWITCHING FUELS[1]

Design Parameter	Distillate Oil Fired, Fire Tube Boiler		Medium Btu Gas Fired, Fire Tube Boiler		Low Sulfur Coal Stoker Fired, Water Tube Boiler[2]	
Capacity						
(MW)	4.4		4.4		4.4	
(10^6 Btu/hr)	15		15		15	
Fuel Analysis						
% Sulfur	0.5		Trace		0.6	
% Ash	Trace		Trace		5.4	
HHV	38.8 (MJ/l) 139,000 (Btu/gal)		11.2 (MJ/m^3) 300 (Btu/scf)		22,370 (kJ/kg) 9,600 (Btu/lb)	
Excess Air (%)	15		15		50	
Flue Gas Flow Rate						
(Nm^3/hr)	5160		4640		6450	
(acfm)	5000		4500		6250	
Flue Gas Temperature						
(°C)	177		177		177	
(°F)	350		350		350	
Load Factor (%)	45		45		45	
Emission Rate[3]	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)
particulates	0.14	0.315	0.023	0.05	9.59	21.1
sulfur dioxide	3.34	7.35	0.004	0.01	6.00	13.2
nitrogen oxides as NO_2	1.36	3.00	0.341-1.02	0.75-2.25	2.45	5.4
carbon monoxide	0.25	0.54	0.117	0.26	0.75	1.66
hydrocarbons as CH_4	0.05	0.11	0.02	0.045	0.35	0.78

[1] The information in this table is based on data presented in Section 4.0.

[2] Assumes an underfeed stoker (Source: PE-348).

[3] Uncontrolled.

the second and third most probable fuel switches are to medium-Btu gas firing and low-sulfur western coal-firing, respectively. Under the maximum impact of the NEP, low-sulfur western coal is the second most likely fuel switch. No fuel switching is expected for the first three cases, but if the supply of distillate oil to the boiler becomes unsure, some switching may occur. A limited number of boilers will switch to medium-Btu gas and some may switch to low-sulfur western coal by boiler replacement.

TABLE 5-21. EXPECTED FUEL SWITCHES FOR A 4.4 MW DISTILLATE OIL FIRED BOILER

Rank[1]	Basis			
	No Regulations	Typical State Regulations	Minimum Impact of NEP	Maximum Impact of NEP
1st	None	None	None	Medium-Btu gas
2nd	Medium-Btu gas	Medium-Btu gas	Medium-Btu gas	None
3rd	Low-sulfur western coal	Low-sulfur western coal	Low-sulfur western coal	Low-sulfur western coal

[1] The rank is based on the annual costs in Tables 5-13, 5-14, and 5-15.

Table 5-22 presents estimated values for the design parameters of the 4.4 MW (15 x 10^6 Btu/hr) distillate oil-fired boiler after switching fuels to medium-Btu gas and low-sulfur western coal. Pollutant rates are for uncontrolled emissions. The values presented in Table 5-22 are based on information contained in Section 4.0 of this report and PEDCo's "Design Parameters For Standard Boilers" (PE-348).

5.5.3 44 MW Residual Oil-Fired, Water Tube Boiler

The annual costs associated with fuel switching in a 44 MW (150 x 10^6 Btu/hr), residual oil-fired, water tube boiler were estimated for four sets of conditions. Based on these estimates, the expected fuel switches were

TABLE 5-22. DESIGN PARAMETERS FOR A 4.4 MW DISTILLATE OIL FIRED BOILER AFTER SWITCHING FUELS[1]

Design Parameter	Medium-Btu Gas Fired, Fire Tube Boiler		Low-Sulfur Coal Stoker Fired, Water Tube Boiler[2]	
Capacity				
(MW)	3.7		4.4	
(10^6 Btu/hr)	12.8		15	
Fuel Analysis				
% Sulfur	Trace		0.6	
% Ash	Trace		5.4	
HHV	11.2 (MJ/m^3) 300 (Btu/scf)		22,370 (kJ/kg) 9,600 (Btu/lb)	
Excess Air %	15		50	
Flue Gas Flow Rate				
(Nm^3/hr)	3945		6450	
(acfm)	3825		6250	
Flue Gas Temperature				
(°C)	177		177	
(°F)	350		350	
Load Factor %	45		45	
Emission Rate[3]	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)
particulates	0.02	0.04	9.59	21.1
sulfur dioxide	0.003	0.009	6.00	13.2
nitrogen oxides as NO_2	0.29-0.87	0.64-1.91	2.45	5.4
carbon monoxide	0.10	0.22	0.75	1.66
hydrocarbons as CH_4	0.017	0.038	0.35	0.78

---

[1] The information in this table is based on data presented in Section 4.0.

[2] Assumes underfeed stoker (Source: PE-348).

[3] Uncontrolled.

identified and are presented in Table 5-23. As shown, the residual oil fired boiler is expected to switch fuels under all the conditions examined. For the case where no regulatory impact is included in the annual cost estimates, the following five fuel switching scenarios are economically competitive with residual oil firing.

1) Residual oil to low-sulfur western coal firing
2) Residual oil to COM 1 firing
3) Residual oil to COM 2 firing
4) Residual oil to COM 3 firing
5) Residual oil to high-sulfur coal firing

The annual costs associated with each of these scenarios are approximately equal to or lower than the cost of continuing to fire residual oil.

TABLE 5-23. EXPECTED FUEL SWITCHES FOR A 44 MW RESIDUAL OIL FIRED BOILER

Rank[1]	Basis			
	No Regulations	Typical State Regulations	Minimum Impact of NEP	Maximum Impact of NEP
1st	Low-sulfur western coal	Low-sulfur western coal	Low-sulfur western coal	Low-sulfur western coal
2nd	COM 1, COM 3	COM 1, COM 3	COM 1, COM 3	Low-sulfur eastern coal
3rd	COM 2, high-sulfur coal	COM 2	COM 2	High-sulfur coal
4th	None	None	None	COM 1, COM 2, COM 3

[1] The rank is based on the annual costs in Tables 5-16, 5-17, and 5-18.

For the cases in which typical state regulations and the maximum impact of the NEP are included in annual costs, the first four fuel switching scenarios listed above are the most likely to occur. Again, the annual costs for each of these scenarios are equal to or less than the cost of continuing to fire residual oil. For the case in which the maximum impact of the NEP is included in the annual costs, the most probable fuel switch is to low-sulfur western coal firing. The second most likely switch is to low-sulfur eastern coal while the other alternatives are either high-sulfur coal firing or coal-oil mixture firing.

The expected fuel switches presented in Table 5-23 all have annual costs which are competitive with the cost of continuing to fire residual oil. However, this does not mean that the boilers which currently fire residual oil will begin switching fuels. Additional factors which are not included in the cost estimates that form the basis for Table 5-23 must be considered. For conversion to coal firing, the availability of space at the plant site is a key factor. In addition, the price of coal on which the expected fuel switches are based represent minemouth costs and they are probably not typical of fuel costs to industrial users. For conversion to COM firing, the status of development of the technology must be considered. It is unlikely that this technology will be used extensively by industry until the reliability of COM firing is demonstrated. Because of these considerations, it does not appear that existing residual oil fired boilers will switch fuels extensively and the fuel switching method which is most likely to be employed is coal firing by boiler replacement.

Table 5-24 presents estimated values for the design parameters of the 44 MW (150 x 10^6 Btu/hr) residual oil fired boiler after switching fuel to three coal-oil mixtures, and high- and low-sulfur coals. Pollutant rates are for uncontrolled emissions. The values presented in Table 5-24 are based on information contained in Section 4 of this report, and in PEDCo's "Design Parameters For Standard Boilers" (PE-348).

TABLE 5-24. DESIGN PARAMETERS FOR A 44 MW RESIDUAL OIL FIRED BOILER AFTER SWITCHING FUELS[1]

Design Parameter	COM 1 Fired, Water Tube Boiler		COM 2 Fired, Water Tube Boiler		COM 3 Fired, Water Tube Boiler		High-Sulfur Coal Stoker Fired, Water Tube Boiler[2]		Low-Sulfur Eastern Coal Stoker Fired, Water Tube Boiler[2]		Low-Sulfur Western Coal Stoker Fired, Water Tube Boiler[2]	
Capacity												
(MW)	44		44		44		44		44		44	
(10^6 Btu/hr)	150		150		150		150		150		150	
Fuel Analysis												
% Sulfur	3.25		1.95		1.80		3.5		0.9		0.6	
% Ash	5.35		3.50		2.25		10.6		6.9		5.4	
HHV	35,900 (kJ/kg) 15,400 (Btu/lb)		38,200 (kJ/kg) 16,400 (Btu/lb)		33,300 (kJ/kg) 14,300 (Btu/lb)		27,500 (kJ/kg) 11,800 (Btu/hr)		32,150 (kJ/kg) 13,800 (Btu/lb)		22,370 (kJ/kg) 9,600 (Btu/lb)	
Excess Air %	32.5		32.5		32.5		50		50		50	
Flue Gas Flow Rate												
(Nm^3/hr)	54,330		53,980		52,510		66,870		62,750		64,810	
(acfm)	54,270		53,920		52,450		64,800		60,800		62,800	
Flue Gas Temperature												
(°C)	190		190		190		177		177		177	
(°F)	375		375		375		350		350		350	
Load Factor %	55		55		55		55		55		55	
Emission Rate[3]	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)	(kg/hr)	(lb/hr)
particulates	171.82	378.0	106.36	234.0	96.14	211.5	172.22	378.88	95.71	210.56	107.77	237.02
sulfur dioxide	237.27	522.0	149.32	128.5	161.59	355.5	404.73	890.40	88.85	195.48	85.18	187.40
nitrogen oxides as NO_2	30.68	67.5	30.68	67.5	30.68	67.5	39.61	87.15	39.61	87.15	39.61	87.15
carbon monoxide	2.51	5.52	2.36	5.19	2.70	5.94	5.78	12.72	4.94	10.86	7.10	15.62
hydrocarbons as CH_4	0.61	1.35	0.58	1.27	0.66	1.45	2.90	6.37	2.47	5.43	3.55	7.80

---

[1] The information in this table is based on data presented in Section 4.0.

[2] Assumes a spreader stoker (Source: PE-348).

[3] Uncontrolled.

REFERENCES

AS-068 Ashworth, Robert A. "Coal gasification economics-onsite vs. central plant, and retrofitting to low and intermediate Btu gas". Presented at the Fourth Annual International Conference on Coal Gasification, Liquefaction and Conversion to Electricity. Pittsburgh, PA. August 1977.

BA-448 Ball, D.A., *et al.* Environmental Aspects of Retrofitting Two Industries to Low- and Intermediate-Energy Gas from Coal. EPA-600/2-76-102, EPA Contract No. 68-02-1843. Battelle-Columbus Laboratories. Columbus, Ohio. April 1976.

BA-477 Babcock and Wilcox Company. Low-Btu Gas Study. Final Report. EPRI 265-2, PB 251 442. Barberton, OH. January 1976.

BA-669 Bagge, Carl E. "Coal by Demand, Not Command: Is Retrofit Realistic?" Energy 2(3), 29-30 (1977).

BE-465 Bechtel, Corp. Evaluation of Dry Alkalis for Removing Sulfur Dioxide From Boiler Flue Gases. Final Report. EPRI FP-207, Research Project 491-1. San Francisco, CA. October 1976.

BE-530 Bell, Arlen W. and Bernard P. Breen. "Converting Gas Boilers to Oil and Coal." Chem. Eng. 1976 (April 26), 93.

BE-531 Bergman, P.D., *et al.* "Economic Considerations for Industrial Firing of Coal-Oil Mixtures." Presented at the First International Symposium on Coal-Oil Mixture Combustion. St. Petersburg, FL. May 1978.

BL-147 Blythe, Gary M. and William E. Corbett. A State-of-the-Art Survey of Control Techniques for the Abatement of NO Emissions From Stationary Combustion Sources. Radian Project No. 200-045-47, TN No. 200-045-47-02. Radian Corp. Austin, TX. July 1976.

BR-493 Brown, A., Jr., ed. Powdered Coal-Oil Mixtures (COM) Program For The Period March 1975-July 1977. Final Report. ERDA Contract No. EX-76-C-01-2267, FE-2267-2. General Motors Corporation, Plant Engineering Development. Warren, MI.

BR-508 Brickhill, J.A. Impact of Natural Gas Shortage on Major Industrial Fuel-burning Installations, 3 Vols. EPA Contract No. 68-02-1452, EPA 450/3-77-017a,b,c. Vol. 1-Text, vol. 2-Schedules, vol.3-Fuel-burning characteristics of MFBIs. Foster Associates, Inc., Energy Division. Washington, D.C. March 1977.

BU-342 Busch, Charles F. and Richard A. Brown. "Parametric Study of Coal-Oil Mixture Combustion." Presented at the First International Symposium on Coal-Oil Mixture Combustion. St. Petersburg, FL. May 1978.

BU-343 Burbach, H.E. and A. Bogot. "Design Considerations for Coal-Fired Steam Generators." Presented at the Annual Conference of the Association of Rural Electrical Generating Cooperatives. Wichita, KS. June 1976.

CA-451 Cavanaugh, E.C., W.E. Corbett, and G.C. Page. Environmental Assessment Data Base for Low/Medium-Btu Gasification Technology, 2 Vols. DCN 77-200-143-26. EPA Contract No. 68-02-2147, PB274, 44, EPA 600/7-17-125a,b. Vol. 1-Technical discussion, vol. 2-Appendices A-F. Radian Corp. Austin, TX. November 1977.

CH-476 Christie, G.A., J.D. Wills, and R.G. Winklepleck. "Coal-Oil Mixture (COM): A Preliminary U.S. Market Study." Presented at the First International Symposium on Coal-Oil Mixture Combustion. St. Petersburg, FL. May 1978.

CO-735 Coles, W.F. and J.T. Stewart. "Considerations When Converting Industrial Plants to Coal Firing." Presented at the ASME Industrial Power Conference. Cleveland, OH. October 1977.

DE-339 "DOE (Department of Energy) to Focus Coal Conversion Orders on New Plants". Electrical Week 1978 (June 19), 11.

DI-163 Dickerman, J.C., *et al.* An Investigation of the Use of Coal in the HL&P Generating System, 4 Vols. DCN 77-200-162-02. Houston Lighting and Power Contract No. L-56904. Radian Corp. Austin, TX. July 1977.

EG-016 Egan, Tom. The Impact of Future Gas Curtailments, Coal Conversion Options, and Air Emission Standards on California's Industrial Boilers - A Simulation Analysis. Interim Report, 3 Vols. ERCDC Contract No. 110-004 (7-8). University of California, Dept. of Economics. Davis, CA. March 1978.

EL-052 El Paso Natural Gas Co. Application of El Paso Natural Gas Co. for a Certificate of Public Convenience and Necessity. Docket No. CP73-131. El Paso, TX. 1973.

EN-761 Energy and Environmental Analysis. Economic Impacts, Section 8 From a Main Report, Unpublished. Arlington, VA. September 1977.

FE-260 Federal Energy Administration, Office of Coal Utilization. Coal Conversion Program. Energy Supply and Environmental Coordination Act (As Amended) Section 2. Final Revised Environmental Impact Statement, Vol. 1. FES-77-3, FEA/G-77/145. Washington, D.C. GPO. May 1977.

FR-198 Frendberg, A.M. "Effects of Fuel Changes on Boiler Performance". Presented at the Pacific Coast Association Engineering and Operating Conference. San Francisco CA. March 1976.

FR-277 Freedman, S.I., C.B. Foster, and E.M. Jamgochian. "Technical Aspects of Coal-Oil Mixture Combustion." CONF-780206. Presented at the Society of Engineers of AIME 1978 Annual Meeting. Denver, CO. February 26-March 2, 1978.

FU-100 Fuel Switching Forum, Pittsburgh, PA., June 1977, Proceedings. Conf. 770658. Washington, D.C. U.S. Department of Energy. November 1977.

GI-155 Gibbs, L., (Program Manager, PEDCo-Environmental Inc., Cincinnatti, OH). Private communication with Jack Burke, Jim Dickerman, Gary Jones, and Bill Thomas, 10 August 1978.

HI-220 Hittman Associates, Inc. Coal Liquids for Industrial Boilers, Emission Control Techniques. Interim Draft Report, Section 2. EPA Contract No. 68-02-2162, Task 22. Columbia, MD. August 1978.

HU-234 Huggins, David Anthony and Norman Chriatian Nussen. "Precipitation des sulfures de nickel et/ou de cobalt et/ou de zinc filtrables a partir de solutions acides". French Patent 2, 198,897. May 1974.

IC-005 ICF Inc. Economic Considerations in Industrial Boiler Fuel Choice. Final Report. Washington, D.C. June 1978.

IN-181 Industrial Gas Cleaning Institute. Particulate Emission Control Costs for Intermediate-Sized Boilers. EPA Contract No. 68-02-1473, Task No. 18. Stamford, CT. February 1977.

MC-120 McKenna, John D. Applying Fabric Filtration to Coal-Fired Industrial Boilers (a Preliminary Pilot Scale Investigation). Final Report. EPA Contract No. 68-02-1093. EPA 650/2-74-058. Roancke, VA. Enviro-Systems and Research, Inc. 1974.

NA-419 National Research Council, Commission on Sociotechnical Systems, Ad Hoc Panel on Liquefaction of Coal of the Committee on Processing and Utilization of Fossil Fuel. Assessment of Technology for the Liquefaction of Coal, 2 Vols. ERDA Contract No. E(49-18)-1216. National Academy of Sciences. Washington, D.C. 1977.

OL-065 Olsen, David L., *et al.* Market Opportunities for Low- and Intermediate-Btu Gas from Coal in Selected Areas of Industrial Concentration, June 1976-April 1978. Final Report. DOE Contract No. E(49-18)-2441, FE-2441-2. Menlo Park, CA. SRI International. April 1978.

PE-289 PEDCo Environmental Services, Inc. Impact of the SO_2 Emission Standards Level on the Methods and Costs of Compliance for New Power Plants. EPA Contract No. 68-02-1076, Task 18. November 1975.

PE-346 PEDCo Environmental Services, Inc. Technical Support for New Source Performance Standards for Industrial Boilers, Preliminary Summary of the Industrial Boiler Population. EPA Contract No. 68-02-2603, Assignment No. 19, Task 2. Cincinnati, OH. June 1978.

PE-348 PEDCo Environmental Specialists, Inc. Private communication with J.M. Burke, July 1978.

PO-097 "Power from Coal - Pt. 1. Coal Selection and Handling." Power 1974 (Feb.), S1.

PO-098 "Power from Coal. Pt. 2. Coal Combustion." Power 1974 (March), S25.

PR-203 Price, Wilma. "Study Forecasts No Big Switch to Coal". Chem. Eng. 1978 (July 31), 48.

SC-273 Schreiber, R., *et al.* Boiler Modification Cost Survey for Sulfur Oxides Control by Fuel Substitution. Contract No. 68-02-1318. EPA 650/2-74-123. Acurex Corp. Mountain View, CA. November 1974.

SC-402 Schwieger, Bob. "Industrial Boilers--What's Happening Today." Power 121(2), 51-52 (1977).

SC-538 Schweiger, R., ed. "Review Provisions of Key Federal Energy and Environmental Laws". Power 122(10), 68 (1978).

SM-201 Smith, V.L. (Manager, Market Data and Forecasting, Babcock & Wilcox). Private Communication with J.M. Burke. June 21, 1978.

ST-562 Stern, R.D., *et al.* Interagency Flue Gas Desulfurization Evaluation. Revised Draft Report, 2 Vols. DCN 77-200-187-16-10. Radian Corporation. Austin, TX. November 1977.

US-768 U.S. Executive Office of the President, Energy Policy and Planning. Replacing Oil and Gas with Coal and Other Fuels in the Industrial and Utility Sectors. June 1977.